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Presidential Documents

Title 3—

The President

Presidential Determination No. 2004–36 of June 15, 2004

Suspension of Limitations Under the Jerusalem Embassy Act

Memorandum for the Secretary of State

Pursuant to the authority vested in me as President by the Constitution and the laws of the United States, including section 7(a) of the Jerusalem Embassy Act of 1995 (Public Law 104–45) (the "Act"), I hereby determine that it is necessary to protect the national security interests of the United States to suspend for a period of 6 months the limitations set forth in sections 3(b) and 7(b) of the Act. My Administration remains committed to beginning the process of moving our embassy to Jerusalem.

You are hereby authorized and directed to transmit this determination to the Congress, accompanied by a report in accordance with section 7(a) of the Act, and to publish the determination in the **Federal Register**.

This suspension shall take effect after transmission of this determination and report to the Congress.

THE WHITE HOUSE,
Washington, June 15, 2004.

[FR Doc. 04–14839
Filed 6–28–04; 8:45 am]
Billing code 4710–10–P

Presidential Documents

Presidential Determination No. 2004–37 of June 16, 2004

Designation of the Islamic Republic of Pakistan as a Major Non-NATO Ally

Memorandum for the Secretary of State

Consistent with the authority vested in me by section 517 of the Foreign Assistance Act of 1961, as amended (the "Act"), I hereby designate the Islamic Republic of Pakistan as a Major Non-NATO Ally of the United States for the purposes of the Act and the Arms Export Control Act.

You are authorized and directed to publish this determination in the **Federal Register**.

THE WHITE HOUSE,
Washington, June 16, 2004.

[FR Doc. 04–14840
Filed 6–28–04; 8:45 am]
Billing code 4710–10–P

Rules and Regulations

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FEDERAL HOUSING FINANCE BOARD

12 CFR Parts 900 and 998

[No. 2004–07]

RIN 3069–AB22

Registration of Federal Home Loan Bank Equity Securities

AGENCY: Federal Housing Finance Board.

ACTION: Final rule.

SUMMARY: The Federal Housing Finance Board (Finance Board) is issuing a final rule requiring each Federal Home Loan Bank (Bank) to register a class of its equity securities with the Securities and Exchange Commission (SEC) under the registration provisions of section 12(g)(1) of the Securities Exchange Act of 1934 (1934 Act).[1] Each Bank shall thereafter be required to comply with the disclosure requirements of the 1934 Act by preparing and filing with the SEC the annual, quarterly, and current reports required under that Act, as well as any other materials required by the SEC, including those related to audited financial statements.

DATES: *Effective Date:* The final rule will be effective on July 29, 2004.

FOR FURTHER INFORMATION CONTACT: Joseph A. McKenzie, Deputy Chief Economist, Office of Supervision, 202–408–2845, *mckenziej@fhfb.gov;* Neil R. Crowley, Deputy General Counsel, 202–408–2990, *crowleyn@fhfb.gov;* John Harry Jorgenson, Of Counsel, 202–408–2560, *jorgensonh@fhfb.gov;* John P. Foley, Senior Attorney-Advisor, Office of General Counsel, 202–408–2932, *foleyj@fhfb.gov,* Federal Housing Finance Board, 1777 F Street, NW., Washington, DC 20006.

SUPPLEMENTARY INFORMATION: To assist readers, below is an outline of the discussion contained in this **SUPPLEMENTARY INFORMATION:**

I. Statutory and Regulatory Background

A. The Federal Home Loan Bank System (Bank System)

The Bank System consists of 12 Banks and the Office of Finance (OF). The Banks are instrumentalities of the United States organized under the authority of the Federal Home Loan Bank Act (Bank Act).[2] The Banks also are "government sponsored enterprises" (GSEs), *i.e.,* federally-chartered but privately-owned institutions created by Congress to support the financing of housing and community lending by their members.[3] OF is a joint office of the Banks created by the Federal Home Loan Bank Board, which was the predecessor agency to the Finance Board. As a "joint office," OF is not a separate legal entity.

By virtue of their GSE status and the AAA credit rating awarded to Bank System debt, the Banks are able to borrow in the capital markets at favorable rates. The Banks then pass along that funding advantage to their members—and ultimately to consumers—by providing advances (secured loans) and other financial services to their members (principally, depository institutions) at rates that the members generally could not obtain elsewhere. In recent years, the Banks have established acquired member asset (AMA) programs under which the Banks acquire certain residential mortgage loans from their members and certain eligible housing associates (such as state housing finance agencies). The AMA programs represent a means of advancing the Banks' housing finance mission, pursuant to criteria established in Finance Board regulations.[4]

The Banks are cooperatives, meaning that only their members may own the capital stock and share in the profits of the Banks and only their members and certain eligible housing associates may borrow from or use the other products and services provided by the Banks.[5] An institution that is eligible may become a member of a Bank if it satisfies certain statutory and regulatory criteria and purchases a specified amount of the Bank's capital stock.[6]

The Bank System operates under the supervision of the Finance Board, an independent agency created in 1989 within the executive branch of the U.S. government.[7] The primary duty of the Finance Board is to ensure that the Banks operate in a financially safe and sound manner. Consistent with that duty, the Finance Board is required to supervise the Banks, ensure that they carry out their housing finance mission, and ensure that they remain adequately capitalized and able to raise funds in the capital markets.[8]

[1] 15 U.S.C. 78a *et seq.*

[2] 12 U.S.C. 1421 *et seq.*

[3] *See* 12 U.S.C. 1422a(a)(3)(B)(ii), 1430(i), and 1430(j).

[4] *See* 12 CFR part 955.

[5] *See* 12 U.S.C. 1426, 1430(a), and 1430b.

[6] *See* 12 U.S.C. 1424 and 1426; 12 CFR part 925.

[7] *See* Financial Institutions Reform, Recovery, and Enforcement Act of 1989, Pub. L. 101–73, Title VII, sec. 702(a), 103 Stat. 413 (*codified at* 12 U.S.C. 1422a and 1422b).

[8] *See* 12 U.S.C. 1422a(a)(3)(A) and (B).

B. Bank Securities

Each Bank individually issues equity securities to its members.[9] A member is required to purchase and hold stock of its district Bank as a condition both of membership in the Bank and of doing business with the Bank. Members also may acquire stock, often referred to as "excess stock," in excess of the levels required to maintain membership or to support its business with its Bank.

Until the enactment of the Gramm-Leach-Bliley Act in 1999,[10] the Bank Act authorized the Banks to issue only one class of stock to their members.[11] This stock was redeemable in cash at par value six months after a member filed a notice to withdraw from the Bank.[12] The GLB Act altered the capital structure of the Banks. Under the GLB Act's amendments to the Bank Act, a Bank may issue one or both of two classes of stock. Class A stock is redeemable at par value six months after a member files a notice with the Bank to redeem the stock, and Class B stock is redeemable at par value five years after a member files a redemption notice.[13] A Bank also may repurchase, at par value, any excess stock acquired by a member. All stock purchases and redemptions are subject to certain limits relating to the Bank's capital adequacy.[14]

The GLB Act also required each Bank to adopt a capital plan in which the Bank must set forth, among other items, the attributes associated with each class (or subclass) of stock that the Bank intends to issue, including each class of stock's par value, dividend rights and preferences, and liquidation rights.[15] Until a Bank implements its capital plan, its capital structure, including its authority with regard to issuance of stock, is governed by the Bank Act requirements that were in effect immediately prior to the passage of the GLB Act.[16]

The Banks also issue debt securities, known as consolidated obligations (COs), to investors throughout the United States and the rest of the world, pursuant to section 11(a) of the Bank Act, subject to certain conditions.[17] Among the conditions are that the COs may only be issued through OF as agent for the Banks jointly, and that the Banks shall be jointly and severally liable on all COs issued by OF on the Banks' behalf.[18] While the Banks may issue debt jointly through OF, a Bank is not allowed to issue debt individually in its own name. As of March 31, 2004, the Bank System had $603.0 billion of CO bonds (with a maturity of one year or more) and $161.9 billion of CO discount notes (with a maturity of less than one year) outstanding.

C. Current Bank System Disclosure

1. Bank System Combined Reports

The Finance Board's regulations currently require OF to prepare and distribute combined annual and quarterly financial reports for the Bank System (Bank System Combined Reports).[19] The disclosure in the Bank System Combined Reports must be generally consistent in scope, form, and content with the requirements of SEC Regulations S–X and S–K,[20] subject to exceptions that the Finance Board has approved for certain non-financial statement information.[21]

The Bank System Combined Reports also contain discussions of certain non-financial information on an aggregate Bank System level, such as a description of Bank System businesses, and a financial discussion and analysis. Information about each Bank is required to be presented in the Bank System Combined Reports as a segment of the Bank System as if Statement of Financial Accounting Standards No. 131, titled "Disclosures about Segments of an Enterprise and Related Information" (FASB 131), applied to the Bank System Combined Reports.[22]

To facilitate OF's preparation of the annual and quarterly Bank System Combined Reports, the Finance Board's regulations require each Bank to provide to OF, in such form and within such timeframes as the Finance Board or OF shall specify, all financial and other information and assistance OF shall request for that purpose.[23] The financial statements of the Banks must be audited in accordance with generally accepted auditing standards (GAAS) and Federal government auditing standards.[24]

2. Individual Bank Annual and Quarterly Reports

Each Bank currently prepares and distributes to its members an annual report containing audited financial statements, a section containing some level of management discussion and analysis, and discussions of other aspects of Bank operations. Each Bank also distributes unaudited quarterly or semi-annual summary financial reports to its members, with most of the reports being brief. The Finance Board's regulations require that any financial statements contained in an annual or quarterly financial report issued by an

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[9] *See* 12 U.S.C. 1426a(4)(A).

[10] Pub. L. 106–102, 133 Stat. 1338 (Nov. 12, 1999) (GLB Act).

[11] *See* 12 U.S.C. 1426 (1994).

[12] *Id.*

[13] *See* 12 U.S.C. 1426(a)(4)(A).

[14] *See* 12 U.S.C. 1426(e)(1) (2004); 12 U.S.C. 1426 (1994); 12 CFR 931.7(b).

[15] *See* 12 U.S.C. 1426(c); 12 CFR 933.2.

[16] *See* 12 U.S.C. 1426(a)(6). All of the Banks have had their capital plans approved by the Finance Board, and eight Banks have implemented their capital plans as of the date of the adoption of this final rule.

[17] Section 11 of the Bank Act provides three options for raising funds in the capital markets for the Banks. Section 11(a) authorizes the individual Banks to issue debt securities, subject to rules and regulations, terms and conditions prescribed by the Finance Board. 12 U.S.C. 1431(a). Section 11(b) authorizes the Finance Board to issue consolidated debentures, within stated limitations, and upon such terms and conditions as the Finance Board may prescribe, which shall be the joint and several obligations of all of the Banks. *See* 12 U.S.C. 1431(b). Section 11(c) authorizes the Finance Board to issue secured consolidated bonds, upon such terms and conditions as the Finance Board may prescribe, which shall be the joint and several obligations of the Banks. *See* 12 U.S.C. 1431(c).

Under section 15 of the Bank Act, obligations of the Banks issued with the approval of the Finance Board must state that they are not the obligations of, and are not guaranteed by, the United States. *See* 12 U.S.C. 1435. The Federal Housing Enterprises Financial Safety and Soundness Act of 1992 provides that none of the housing GSE obligations or securities is backed by the full faith and credit of the United States. *See* Pub. L. 102–550, Tit. XIII, sec. 1304, 106 Stat. 3944 (Oct. 28, 1992) (*codified at* 12 U.S.C. 4503). Notwithstanding these statements, the capital markets often view debt issued by or on behalf of the Banks as having an implied government guarantee based on the GSE status of the Banks, the joint and several liability of the Banks on the COs, and the existence of section 11(i) of the Bank Act (12 U.S.C. 1431(i)), which provides that the Secretary of the Treasury is authorized, in his discretion, to purchase up to $4 billion of obligations of the Banks issued under section 11. The Secretary's purchase or sale of such obligations would be treated as "public-debt transactions of the United States."

[18] *See* 12 CFR 966.2(b), 966.9, 985.3(a), and 985.6(a). Prior to 2001, the Finance Board issued COs pursuant to section 11(c) of the Bank Act through OF. The functions currently performed by OF as agent for the Banks with regard to the CO issuance are largely identical to the functions it performed on behalf of the Finance Board when the Finance Board issued the COs. While the Finance Board has retained the authority to issue debt on behalf of the Banks pursuant to section 11(c) of the Bank Act, it currently does not do so. *See* 12 CFR 966.2(a).

[19] *See* 12 CFR 985.6(b).

[20] SEC Regulation S–K specifies disclosure rules for non-financial items to be included in registration statements, annual reports, and proxy statements. *See* 17 CFR part 229. Major items include a description of a registrant's business, management's discussion and analysis, and disagreements with accountants. SEC Regulation S–X, and the SEC's financial reporting releases, set forth the accounting principles that must be utilized in preparing financial statements for inclusion in SEC filings. *See* 17 CFR part 210.

[21] *See* 12 CFR part 985 Appendix A.

[22] *See* 12 CFR 985.6(b)(2).

[23] *See* 12 CFR 989.3.

[24] *See* 12 CFR 989.2. OF also distributes various offering documents to investors in connection with issuances of Bank System COs. These OF discloure documents are modeled on the disclosure documents that are prepared by issuers of investment grade debt.

individual Bank be consistent in both form and content with the financial statements presented in the Bank System Combined Reports prepared by OF.[25] Except for this requirement, there is no other Finance Board regulatory requirement that individual Bank annual or quarterly reports be in scope, form, or content generally consistent with the requirements of SEC Regulations S–K and S–X.

While the financial statements in the Banks' annual and quarterly reports are generally consistent with SEC Regulation S–X, the level of discussions in these reports of non-financial statement information varies from Bank to Bank and is not in all cases generally consistent with 1934 Act disclosure standards.[26] Thus, the major effect of requiring the Banks to register a class of securities with the SEC and subject themselves to an SEC-administered 1934 Act periodic disclosure regime would be greater disclosure by the Banks at the individual Bank level of non-financial statement information, with the attendant benefits discussed below in section II.B.

D. Exemptions for Bank Securities From the Registration Provisions of the 1933 Act and 1934 Act

The Securities Act of 1933 (the 1933 Act) [27] regulates public offerings of securities and prohibits offers and sales of securities that are not registered with the SEC, subject to certain exemptions for enumerated kinds of securities and transactions. The 1934 Act regulates trading in certain securities that are already issued and outstanding and prescribes a robust disclosure regimen for registered entities.

Since enactment of the Bank Act in 1932, the Banks have never registered their debt or equity securities under either the 1933 Act or the 1934 Act. Neither the 1933 Act nor the 1934 Act, however, exempts the Banks from registration by name or otherwise provides special status or unique exemptions for the Banks, although there are generally available exemptions from registration under those Acts for which the Banks may be eligible.

Under section 3(a)(2) of the 1933 Act, securities issued "by any person controlled or supervised by and acting as an instrumentality of the Government of the United States pursuant to authority granted by the Congress of the United States" are exempt from the registration requirements of that Act.[28] Because the Banks are instrumentalities of the Federal government, both the equity and debt securities of the Banks are exempt from the registration requirements of the 1933 Act under this provision.[29]

Under the 1934 Act, the term "exempted securities" is defined to include, among other things, "government securities." [30] The term "government securities" is, in turn, defined to include "securities which are issued or guaranteed by corporations in which the United States has a direct or indirect interest *and which are designated by the Secretary of the Treasury* for exemption as necessary or appropriate in the public interest or for the protection of investors." [31] The debt securities of the Banks have been exempted from the registration requirements of the 1934 Act as a result of action taken by the Secretary of the Treasury in 1937 pursuant to these provisions. In Release 34–1168, dated April 28, 1937, the SEC announced that the Secretary of the Treasury had designated for exemption those debt securities issued by the Federal Home Loan Bank Board (the predecessor agency to the Finance Board) or by the Banks under the authority of section 11 of the Bank Act.[32] The designation specified that the "exemption may be revoked, modified or amended at any time with respect to securities not issued prior to such time." Outstanding Bank COs have been issued under the authority of sections 11(a) and 11(c) of the Bank Act, respectively, and therefore are included within the scope of the Secretary of the Treasury's 1937 designation. By contrast, the Secretary of the Treasury has never designated the equity securities issued by the Banks as being exempted under this provision.

E. Registration Pursuant to the Voluntary Registration Provisions of Section 12(g)(1) of the 1934 Act

Notwithstanding any exemptions for issuers or securities under the 1933 and 1934 Acts, section 12(g)(1) of the 1934 Act provides a mechanism by which equity securities not otherwise required to be registered may nevertheless be registered under provisions of the 1934 Act. Section 12(g)(1) provides, among other things, that an issuer may register any class of equity securities not required to be registered by filing a registration statement pursuant to the provisions of section 12(g).[33] Registration pursuant to section 12(g)(1) subjects registrants to the periodic disclosure requirements put in place under the 1934 Act, as interpreted and administered by the SEC. For the reasons discussed in part II below, the Finance Board has determined, consistent with the proposed rule, to require each Bank to register a class of its equity securities pursuant to the voluntary registration provisions of section 12(g)(1).

F. Proposed Rule

In July 2002, the Undersecretary for Domestic Finance of the United States Department of the Treasury called on all GSEs to follow the lead of the Federal Home Loan Mortgage Corporation (Freddie Mac) and the Federal National Mortgage Association (Fannie Mae) and begin working with the SEC to achieve a 1934 Act securities disclosure regime administered by the SEC.[34] Shortly thereafter, Finance Board staff held a number of meetings with Bank System representatives (collectively, the Bank Disclosure Task Force) to discuss SEC registration and related disclosure requirements. The Finance Board subsequently relayed the Banks' principal concerns on registration issues to SEC staff. On December 2, 2002, the Finance Board held a public hearing to consider enhanced Bank disclosure generally and possible Bank registration under the 1934 Act in particular.[35] Finance Board staff also had numerous discussions with SEC staff on registration issues. In addition, SEC staff met with several Banks to resolve certain accounting and disclosure issues raised by 1934 Act registration.

After gathering information and analyses through these various forums, on September 17, 2003, the Finance Board published for comment a proposed rule that would have required each Bank to agree to register a class of its securities with the SEC under section 12(g) of the 1934 Act within 120 days of the adoption of the rule as a final rule.[36] Registration, and the resulting periodic disclosure requirements under

[25] *See* 12 CFR 989.4.

[26] *See* section II.B.2, below, for additional discussion of the differences between current Bank disclosures required under Federal securities laws.

[27] 15 U.S.C. 77a *et seq.*

[28] *See* 15 U.S.C. 77c(a)(2).

[29] *See* 12 U.S.C. 1431(e)(1). *See also Fahey* v. *O'Melveny & Myers*, 200 F. 2d 420 (9th Cir. 1952), *cert. denied*, 345 U.S. 952 (1953); Merrill Lynch, Pierce, Fenner & Smith, SEC No Action Letter, 1986 SEC No-Act. LEXIS 2877 (Nov. 5, 1986).

[30] *See* 15 U.S.C. 78c(a)(12)(A).

[31] *See* 15 U.S.C. 78c(a)(42)(B) (emphasis added).

[32] SEC Exchange Act Release 1168 (April 28, 1937) (1937 WL 3510).

[33] *See* 15 U.S.C. 78*l*(g)(1).

[34] Fannie Mae subsequently registered its common stock with the SEC under the voluntary registration provisions of section 12(g) of the 1934 Act. Freddie Mac has agreed to register, but has not done so.

[35] Testimony and comments submitted at that hearing may be located at *http://www.fhfb.gov/pressroom/PR02_testimony4.htm.*

[36] *See* 68 FR 54396 (Sept. 17, 2003).

the 1934 Act, would result in the Banks disclosing at the individual Bank level more comprehensive information than currently is provided in individual Bank quarterly and annual reports. The major effect of this new disclosure requirement would be greater disclosure of non-financial statement information by the Banks at the individual Bank level.

The proposed rule also would have required the Banks to provide to the Finance Board on a concurrent basis copies of all disclosure documents filed with the SEC. The proposal expressly provided that it would not limit or restrict the Finance Board's ability to carry out its responsibilities under the Bank Act, including its responsibility to ensure that the Banks operate in a financially safe and sound manner and are able to raise funds in the capital markets.

The Finance Board cited in the **SUPPLEMENTARY INFORMATION** section of the proposed rule three bases for adoption of the rule.[37] First, comprehensive, fully transparent securities disclosure by each Bank under an SEC-administered disclosure regime may help maintain the long-term confidence of the investment community and the national rating agencies, thereby better securing the Bank System's ability to access the capital markets. The SEC establishes the best-practices standard for disclosure, has the resources and expertise to ensure that individual Bank disclosure documents meet this standard, and enhances the credibility of registrants' financial statements through its review of those disclosures.

Second, Bank accounting and financial statement reporting issues have become significantly more complex in recent years due to new Financial Accounting Standards Board (FASB) statements on reporting requirements, necessitating more comprehensive and detailed disclosures by individual Banks. As noted in the proposal, the SEC staff has the extensive accounting expertise required to review this Bank disclosure.

Third, Fannie Mae has voluntarily registered its common stock with the SEC under section 12(g) of the 1934 Act, and Freddie Mac has agreed to do so upon completion of its restatement of its financial statements. The proposal recognized that there may be merit in having the core securities disclosures of all of the housing GSEs overseen by the same disclosure regulator.

The proposed rule provided for a 120-day comment period, which closed on January 15, 2004. The Finance Board received 24 comment letters on the proposed rule. Commenters included: 11 Banks; one Bank member; five financial institution trade associations (with one commenter submitting two separate comments); two housing trade associations; one nonprofit social services organization; one nonprofit community development organization; one Congressional Representative (forwarding the above-mentioned letters from one of the housing trade associations, the social services organization and the community development organization); and one law student.

In general, the commenters supported more comprehensive securities disclosure by the individual Banks, provided such enhanced disclosure takes into account the unique structure of the Banks. Commenters expressed differing views on whether such enhanced disclosures should be overseen by the SEC or the Finance Board, and on the appropriate process for achieving an SEC-administered disclosure regime. Some commenters argued that the Finance Board lacks the legal authority to require SEC registration. Commenters stated that the record lacked factual or empirical evidence supporting the bases for adopting the rule and an analysis of the potential costs and benefits of the rule. The comments, and the Finance Board's responses thereto, are discussed further in part II of this **SUPPLEMENTARY INFORMATION** section.

II. Finance Board Findings Supporting Adoption of the Final Rule

The Finance Board has carefully reviewed the issues raised by the commenters. The Finance Board's review encompassed analysis of: the Finance Board's legal authority to adopt the rule; the individual Banks'' current securities disclosure as compared to the enhanced disclosure requirements, and what exceptions to 1934 Act disclosure requirements might be appropriate due to the unique structure of the Banks; the effect of enhanced disclosure on market discipline, access to the capital markets, and the safe and sound operations of the Banks; and the potential costs and benefits of enhanced disclosure under an SEC-administered, versus a Finance Board-administered, disclosure regime. In conducting this review, the Finance Board considered the comments received on the proposed rule, as well as Finance Board staff analyses and other documents included in the administrative record.

Based on this review, the Finance Board has determined to adopt the proposed rule as a final rule, in substantially similar form and subject to a date by which all Banks must become SEC registrants. The Finance Board's findings supporting the adoption of the final rule are discussed below.

A. Legal Authority To Require Registration

Several commenters stated that the Finance Board lacks the legal authority under the Bank Act to require each Bank to register a class of its securities with the SEC under the voluntary registration provisions of section 12(g) of the 1934 Act.[38] The Finance Board's authority to adopt the rule at issue involves two distinct questions: First, whether the Finance Board may require the Banks to provide enhanced disclosures in furtherance of its mission as the Banks' safety and soundness regulator; and second, if the authority exists as a general matter, whether the Finance Board has the authority to require that the registration be with the SEC.

1. Authority To Require Enhanced Disclosures

As a general proposition, any action taken by a federal regulatory agency must be within the scope of the authority conferred on it by Congress.[39] With respect to the Bank System, Congress has vested supervisory authority with the Finance Board, which is charged with ensuring both the safety and soundness of the Banks and the achievement of their housing

[37] *See* 68 FR 54398.

[38] One commenter requested that the Finance Board seek an advisory opinion from the U.S. Department of Justice's Office of Legal Counsel (OLC) on this issue. The Board of Directors of the Finance Board considered this issue and determined, at its February 11, 2004 meeting, not to seek such an advisory opinion from the OLC. A review by Finance Board staff of numerous OLC opinions requested by or covering federal financial institution regulatory agencies from 1984 to date did not reveal any instances in which such an agency requested an opinion on whether the agency's enabling statute allowed it to take an action relating to its primary statutory mission.

[39] An agency has the power to issue binding legislative rules only to the extent that Congress has delegated such authority to the agency. *See* R. Pierce, *Administrative Law Treatise*, 4th Ed., § 6.4 (Pierce), *citing United States* v. *Storer Broadcasting Co.*, 351 U.S. 192 (1956); *National Broadcasting Co.* v. *United States*, 319 U.S. 190 (1943); *National Petroleum Refiners Ass'n* v. *FTC*, 482 F.2d 672 (D.C. Cir. 1973), *cert. denied*, 415 U.S. 951 (1974). As long as the Finance Board's rule is addressed to, and reasonably adapted to, the enforcement of the Bank Act, it will have the "force and effect of law if it be not in conflict with express statutory provision." *See* Pierce, § 6.4 *citing Maryland Casualty Co.* v. *United States*, 251 U.S. 342, 349 (1920). Generally, Congress has authorized federal agencies to issue binding rules through the use of the notice and comment procedure set forth in section 553 of the Administrative Procedure Act (APA), 5 U.S.C. 551 *et seq. See generally* Pierce, § 6.4, at 341.

finance mission.[40] The Finance Board has plenary authority over the Banks, which is derived from numerous provisions of the Bank Act.[41]

Congress has given the Finance Board broad rulemaking authority to carry out its oversight responsibilities. Specifically, section 2B(a)(1) of the Bank Act authorizes the Finance Board "[t]o supervise the Federal Home Loan Banks and to promulgate and enforce such regulations and orders as are necessary from time to time to carry out the provisions of [the Bank Act]." [42] The language of that provision includes no limitations on the authority of the Finance Board to regulate the Banks or on its authority to adopt regulations, other than that the regulation be necessary to carry out the provisions of the Bank Act. The statute leaves to the Finance Board the discretion to determine what regulations or orders are "necessary" to carry out the provisions of the Bank Act.

The Finance Board's authority to promulgate regulations is sufficiently broad to authorize any regulation duly promulgated by the Finance Board that has the purpose or effect of advancing the safety or soundness of the Banks or any other of the statutory duties of the Finance Board (as well as implementing any specific provision of the Bank Act).[43] As applied to the instant rulemaking, the intent of the Finance Board in adopting a final rule requiring the Banks to provide enhanced disclosures is to advance or promote both the safe and sound operation of the Banks and their continued access to the capital markets through enhanced disclosures. Accordingly, it is within the authority of the Board to require enhanced disclosures.

As courts have recognized, an agency need not show that a particular action is, by itself, crucial to the ability of the agency to fulfill its duties.[44] If the action is "reasonably useful" or "proper" within the context of the agency's overall responsibilities, then it may be adopted pursuant to the authority to issue regulations that are "necessary" to implement other statutory provisions.

2. Authority To Require Registration With the SEC

The Finance Board has analyzed whether Congress has curtailed the agency's authority to require enhanced disclosures. The precise issue before the Finance Board is whether Congress has expressed its intent regarding the registration of Bank securities with the SEC. For the reasons outlined below, we believe that the answer to that question is no.

The Bank Act is a comprehensive statute that addresses virtually all aspects of the Bank System. Among other things, the Bank Act provides for the incorporation of the Banks, their corporate structure, their capital structure, their powers and duties, their membership base, their lending and investment powers, their borrowing authority, their tax status, and the circumstances under which they may be liquidated. In a similar fashion, the Bank Act provides for the creation of the Finance Board, confers on it both general and specific supervisory responsibilities and powers, and generally gives it "cradle to grave" supervisory authority over the Banks.[45] Nowhere, however, does the Bank Act speak expressly to the issue of Bank securities disclosure, either by establishing a unique disclosure regime for the Banks or by constraining the authority of the Finance Board to do so. Moreover, the Bank Act does not affirmatively exempt the Banks from the registration requirements of the 1934 Act, as do the chartering statutes for the other two housing GSEs, Fannie Mae and Freddie Mac.[46]

In considering whether Congress has addressed the question of the appropriate disclosure regime for the Banks, we also have reviewed provisions of the 1933 Act and the 1934 Act. As discussed in section I.D, above, Bank securities are not currently registered under either the 1933 Act or the 1934 Act. The reasons why Bank securities have not been registered under those Acts vary. For example, under the 1933 Act, Bank debt and equity securities are exempted from the registration provisions as securities issued by a "government instrumentality." Under the 1934 Act, Bank debt and equity securities are not generally exempted (although they may qualify under a more limited exemption or otherwise not be subject to the 1934 Act registration requirements). The Secretary of the Treasury has designated Bank debt securities as exempt from registration, but has not so exempted Bank equity securities.

This lack of uniformity in how Bank securities are treated suggests that Congress had no intention to establish a particular disclosure regime for the Banks under the federal securities laws. Although there are certain exemptions from registration that may be available to the Banks under various provisions of both the 1933 Act and the 1934 Act, none of those exemptions is targeted specifically toward the Banks. Rather, they are generally available to any issuer or type of security that meets the particular requirements for each exemption. As previously noted, Congress has not enacted an express exemption for Bank securities, as it has done in the Charter Acts of Fannie Mae and Freddie Mac, nor has it conferred 1934 Act jurisdiction over the Banks on the Finance Board, as it has done with respect to the regulators of federally

[40] *See* U.S.C. 1422a(a)(3).

[41] *See* 12 U.S.C. 1422b(a)(1) (rulemaking) and 1422a(a)(3) (statutory duties). Other provisions of the Bank Act that confer supervisory authority on the Finance Board include: Section 2B(a)(2), which authorizes the Finance Board to suspend or remove any officer, director, employee or agent of any Bank or joint office for cause, 12 U.S.C. 1422b(a)(2); section 2B(a)(5), which confers administrative enforcement powers that are substantially the same as those possessed by other federal financial institution regulators, 12 U.S.C. 1422b(a)(5); and section 20, which authorizes the Finance Board to examine the Banks and to require reports of condition of all Banks, and which confers on the Finance Board examiners the same powers, duties, privileges, and obligations as federal bank examiners have under the Federal Reserve Act and the National Bank Act, 12 U.S.C. 1440.

[42] *See* 12 U.S.C. 1422b(a)(1).

[43] *See, e.g., Fidelity Federal Savings and Loan Association* v. *De La Cuesta*, 458 U.S. 141, 159—162 (1982) (upholding rule addressing lending practices of savings associations as within scope of delegation from Congress and in furtherance of the purposes of the statute); *Texas Savings & Community Bankers Association, et al.* v. *Federal Housing Finance Board*, No. 98–50758 (5th Cir. 2000) (upholding Finance Board approval of a Bank mortgage loan purchase program); and *WFS Financial Inc.* v. *Dean*, 79 F. Supp. 1024, 1026 (W.D. Wis. (1999)) (upholding rule addressing operating subsidiaries as within delegation of authority from Congress and consistent with advancing purposes of the statute).

[44] *See, e.g., Shinn* v. *Encore Mortgage Services, Inc.*, 96 F. Supp. 2d 419, 424 (D.N.J. 2000) (upholding Office of Thrift Supervision (OTS) rule regulating alternative mortgage transactions as an appropriate exercise of its authority to "prescribe such regulations and issue such orders as the Director may determine to be necessary for carrying out this chapter and all other laws within the Director's jurisdiction."); *Home Mortgage Bank* v. *Ryan*, 986 F.2d 372, 377 (10th Cir. 1993) (upholding OTS merger regulation as a "permissible exercise of OTS's regulatory responsibility over state-chartered savings associations"); *Federal Labor Relations Authority* v. *United States Department of the Navy*, 96 F.2d 747, 752 (3rd Cir. 1992) (upholding the Fair Labor Relations Authority determination that disclosure of home addresses was "necessary" for collective bargaining, and stating that "Congress delegated this sort of specific determination to the FLRA in the Labor Statute."). As stated by the United States Supreme Court, "An agency 'must be given ample latitude to adapt [its] rules and polices to the demands of changing circumstances.'" *Rust* v. *Sullivan*, 500 U.S. 173, 186–187 (1991).

[45] *See* 12 U.S.C. 1422a (creation), 1422b (general powers), 1426 (capital standards), 1427 (designation of directorships/appointment of directors), 1431 (approval/oversight of borrowing), 1440 (examinations), and 1446 (authority to liquidate/reorganize).

[46] Congress has expressly provided that all securities issued by Fannie Mae and Freddie Mac shall be treated as exempt securities under federal securities laws to the same extent as securities that are the direct obligations of the United States. *See* 12 U.S.C. 1723(c) (Fannie Mae's securities) and 12 U.S.C. 1455(g) (Freddie Mac's securities).

insured depository institutions.[47] Based on the absence of any Bank-specific provisions in these laws, and the inconsistent treatment generally afforded to Bank securities, we believe that there is no evidence that Congress intended to establish a particular disclosure regime for the Banks pursuant to the provisions of the federal securities laws or the Bank Act.

In the view of one commenter, the proposal constituted an impermissible delegation of authority by one agency of its responsibilities to another. That commenter cited several cases as supporting the proposition that a federal agency may not delegate statutory decision-making authority to an outside entity without express authority from Congress.[48]

We do not believe that these cases are controlling in the current rulemaking. In each of the cases cited, the courts were faced with specific delegations of authority by Congress to an agency, which the agency then subdelegated to a third party. In short, the agency at issue was relying on a third party to fulfill the agency's responsibilities. In *USTA* v. *FCC*, for instance, the court rejected the FCC's attempt to delegate to state utility commissions its responsibility to make determinations related to requiring telecommunication carriers to open up their infrastructure to competition. Similarly, in *NPS* v. *Stanton*, the court rejected the NPS's attempt to delegate to an outside entity its responsibilities for managing a national scenic river. The common element in the cited cases is that the agency had delegated to an outside party decision-making authority that a statute had required it to perform.[49]

In contrast to the central facts of those cases, the Finance Board, in requiring the Banks to register a class of securities under the 1934 Act, is not delegating to the SEC any of the statutory responsibilities assigned to the Finance Board by section 2A(a)(3) of the Bank Act. The Finance Board remains the sole entity responsible for ensuring that the Banks operate in a financially safe and sound manner and that they remain adequately capitalized and able to raise funds in the capital markets. Instead, the Finance Board, having determined that enhanced disclosure would further its duty to ensure the safety and soundness of the Banks—a point with which the commenters agree—has determined further that registration with the SEC under the 1934 Act would be the most appropriate means to fulfill the Finance Board's statutory duties.

By adopting the regulation, the Finance Board is not abdicating its role as Bank supervisor or giving up any enforcement power but instead is requiring the Banks to subject themselves to a disclosure review by a specialized outside entity. Rather than delegating decision-making authority, the Finance Board is using authority granted under the Bank Act to direct the Banks to avail themselves of an established securities registration regime so that the Finance Board may do its job better. Such action does not violate any explicit prohibition in the Bank Act or the 1934 Act, nor is it contrary to any express intent of Congress.

The ability of the Finance Board to fulfill its responsibilities as the Banks' safety and soundness regulator will be enhanced by improved disclosures that are on a par with disclosures in other businesses, including the other housing GSEs.[50] The discipline imposed by debt and equity investors on the operations of financial institutions has come to be viewed as an important complement to minimum capital requirements and the supervisory review process in ensuring the safe and sound operation of a financial institution. Adequate and consistent disclosure is an important element in achieving market discipline, since it is through such disclosure that market participants gain access to information on the risks faced by the institution in question. Critical to that process is the ability to compare information across similar institutions at a point in time and over time.

As is well recognized, public disclosure is not a replacement for regulatory oversight but is an important complement to the regulatory and supervisory oversight process in ensuring the safe and sound operation of a financial institution.[51] In this respect, the registration rule is analogous to existing requirements that Banks and OF annually submit to accounting audits by an independent external auditor.[52] The rule also is analogous to the Finance Board regulation that conditions the acceptability of certain investments on ratings received from a nationally recognized statistical rating organization (NRSRO).[53]

In several of the cases cited by the commenter, the entity receiving delegated powers had no independent authority to act. Here, the SEC's authority to accept the Banks as registrants and to oversee disclosure comes from the 1934 Act itself, not from any power delegated to it by the Finance Board.[54] Given the SEC's well-established authority to regulate securities disclosure, it is reasonable for the Finance Board to rely on the SEC's expertise in this area, absent a specific expression that Congress did not intend such an outcome.

Congress specifically provided that issuers that are not required to register under the 1934 Act could avail themselves of the benefits of SEC disclosure by "voluntarily" registering their stock, and authorized the SEC to accept such registration.[55] One

[47] *See* section 12(i) of the 1934 Act, codified at 15 U.S.C. 78l(i). Under section 12(i), certain federally insured depository institutions that are subject to the 1934 Act registration requirements must make their 1934 Act disclosure filings with the federal banking regulator that supervises their operations. Section 12(i) requires the banking agency to adopt substantially similar disclosure regulations as those adopted by the SEC, unless it finds that implementation of a regulation is not necessary or appropriate in the public interest or for the protection of investors. The agency must publish a detailed explanation of the reasons for its departure from the 1934 Act rules in the **Federal Register**. The number of depository institutions making 1934 Act filings with their banking regulators is rather small. For example, 17 state member banks (out of 949 such banks) made such filings with the Federal Reserve (as of December 31, 2002), and 15 savings associations (out of 928 such associations) make such filings with the OTS.

[48] The primary cases cited by the commenter include *United States Telecom Ass'n (USTA)* v. *FCC*, 2004 WL 374262 (D.C. Cir. March 2, 2004); and *National Park Service (NPS)* v. *Stanton*, 54 F. Supp. 2d 7 (D.D.C. 1999).

[49] Other cases cited by the commenter also are not persuasive or applicable to this rule-making. The other cases deal with situations in which: (i) An agency attempted to exercise authority which Congress clearly had not granted it (*ETSI Pipeline Project* v. *Missouri*, 484 U.S. 495 (1988)); (ii) a party (unsuccessfully) challenged the constitutionality of the delegation by Congress of decision-making authority to an agency as lacking sufficient standards (*Touby* v. *United States*, 500 U.S. 160 (1991)); or (iii) the delegation was in violation of the clear terms of the statute in question (*Shook* v. *DC Financial Responsibility and Management Assistance Authority*, 132 F.3d 775 (DC Cir. 1998)).

[50] This point is discussed in greater detail in Section II.B of this SUPPLEMENTARY INFORMATION.

[51] *See, e.g.*, Basel Committee on Banking Supervision, Consultative Document: The New Basel Capital Accord Part 4 (April 2003) (Basel II).

[52] *See* 12 CFR 989.2.

[53] 12 CFR 955.3(a) and 956.3.

[54] In fact, the SEC registration rule appears to be closer to the use of an outside entity that the D.C. Circuit distinguished as not covered by the non-delegation doctrine in one of the cases cited by the commenter. *USTA* v. *FCC*, 2004 WL 374262. The *USTA* court distinguished the delegation at issue before it with the facts of *U.S.* v. *Matherson*, 367 F. Supp. 779 (E.D.N.Y. 1973), in which the court upheld the regulations by an official of the Department of the Interior requiring an applicant for a permit to drive in a national seashore park to first obtain a permit from one of the neighboring municipalities. The *Matherson* Court found that the Superintendent's regulation "is in no way an abdication of the Superintendent's power to administer the National Seashore. Rather, the instant section merely exemplifies an effort by the Superintendent to facilitate an orderly prevention of erosion on the land."

[55] *See* 15 U.S.C. 78l(g).

commenter criticized the Finance Board's proposal on the ground that there was nothing voluntary about the proposal and, therefore, the provisions in the 1934 Act governing voluntary registrations are inapplicable. The Finance Board agrees that its rule makes registration of securities with the SEC mandatory. However, it does so as a requirement stemming from the *Bank Act.* References in the proposal to voluntary registration with the SEC simply underscore that those not otherwise required by the *federal securities laws* may register with the SEC. Thus, there is no inconsistency to say that registration is mandatory under the banking laws while done so in accordance with the procedures available to those who are not otherwise subject to 1934 Act registration requirements.

The issue of whether voluntary registration under the 1934 Act is available for disclosures that are mandated by some other law is a question of interpretation of the securities law. In that regard, the Finance Board is persuaded by the views of the SEC. In testimony delivered before the Committee on Banking, Housing, and Urban Affairs of the United States Senate on February 10, 2004, by Alan L. Beller, Director of the Division of Corporation Finance of the SEC (the Beller Testimony), Mr. Beller stated:

> Since at least 1992, the Commission has expressed the view that, because the GSEs, most prominently Fannie Mae and Freddie Mac, but also including the Federal Home Loan Banks, sell securities to the public and have public investors, and do not have the "full faith and credit" government backing of government securities, their disclosures should comply with the disclosure requirements of the federal securities laws. * * * [T]he manner by which mandatory compliance is achieved—*including through voluntary registration with the Commission*—may be less significant.[56]

Thus, the SEC interprets the 1934 Act in a way that permits filings under the provisions governing voluntary registration, notwithstanding that the registration is required by some other law or regulation.

B. Reasonable Exercise of Finance Board Authority

Based on its review and analysis of the record, the Finance Board has determined that there is a reasonable basis to conclude that requiring enhanced Bank securities disclosure under an SEC-administered periodic disclosure regime under the 1934 Act will assist the Finance Board in carrying out its primary duty to ensure that the Banks operate in a financially safe and sound manner and that they have access to capital markets.

1. Benefits of Enhanced Disclosure Generally

The benefits of enhanced disclosure have been well documented. A leading study in this area, conducted by staff at the Federal Reserve Board (FRB Study), documents how enhanced disclosure of a commercial bank's business risks and financial information can supplement the existing oversight regime for such banks.[57] The FRB Study notes that banking regulators have increasingly accepted the fact that market discipline can serve as one element of an effective program of bank supervision, and discusses in detail how the concepts of financial disclosure, market discipline, and bank supervision are interrelated.

Briefly stated, the stakeholders of a banking institution, by deciding what return they are willing to accept on their investments in a bank's securities, can effectively determine the availability and cost of the bank's funding and thereby influence the bank's business decisions. This ability to "discipline" a bank's risk-taking through market forces is accepted by banking regulators as contributing to the stability of the banking system. The ability of the stakeholders to exert such influence on a bank, however, depends in large part on whether they can accurately assess its financial condition, risks, and earnings prospects, which, in turn, depends on the quality and extent of the institution's financial disclosures. The FRB Study notes that this recognition of the value of market discipline as a supplement to the regulatory regime has prompted banking regulators to focus on methods of improving the transparency of commercial banks' financial condition through enhanced disclosure. It also has led the other housing GSEs to take steps voluntarily to promote market discipline.

Basel II also underscores the importance of enhanced disclosure. Basel II will establish new international standards on bank capital adequacy, and is intended to improve the existing regulatory capital framework for commercial banking organizations. The Accord is based on three separate "pillars" of supervision. The first pillar consists of the minimum regulatory capital requirements for each banking organization, which will be much the same as the existing Basel capital requirements. The second pillar relates to supervisory review of banking institutions by their regulators, which in part entails an assessment of capital adequacy in light of the overall risks to the bank. The third pillar is market discipline, which the Basel Committee expects will complement both the minimum capital requirements of Pillar 1 and the supervisory review process of Pillar 2 and thereby promote safety and soundness in banks and the financial system. The Basel Committee has explained that "the rationale for Pillar 3 is sufficiently strong to warrant the introduction of disclosure requirements for banks using the New Accord," and that it intends "to encourage market discipline by developing a set of disclosure requirements which will allow market participants to assess key pieces of information on the scope of application, capital, risk exposures, risk assessment processes, and hence the capital adequacy of the institution." [58]

2. Benefits of Disclosures That Are Consistent With Industry Standards

Both the FRB Study and Basel II demonstrate that market discipline has become an accepted element of effective bank supervision, particularly with regard to the adequacy of a banking institution's capital. Full and consistent disclosure is an important element in achieving market discipline because it is only through such disclosure that market participants can obtain, and assess, information on the risks faced by individual financial institutions. Moreover, a common and consistent framework for such disclosure will enhance the ability of market participants to compare information across similar institutions and over time. The Office of Federal Housing Enterprise Oversight (OFHEO) made similar observations about the importance of public disclosure to safety and soundness oversight when it recently adopted disclosure requirements for Fannie Mae and Freddie Mac.[59]

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[56] Beller Testimony at 1 (emphasis added). The Beller Testimony may be located at *http://www.sec.gov/news/testimony/ts021004alb.htm.* SEC staff recently confirmed to the Finance Board that the statements made in that testimony "continue to be accurate and to reflect the views of the [SEC] staff." Letter from Alan Beller to Alicia R. Castaneda, Chairman, Federal Housing Finance Board, June 1, 2004, at 1.

[57] Staff Study 173, *Improving Public Disclosure in Banking,* Federal Reserve Study Group on Disclosure (March 2000).

[58] Basel II, ¶ 757 and ¶ 758.

[59] *See* 68 FR 16715 (April 7, 2003) (adopting 12 CFR part 1730) ("As users of and participants in the financial markets, the success of the Enterprises [*i.e.*, Fannie Mae and Freddie Mac] in meeting their public policy missions and in maintaining their safe and sound operations is inextricably tied to full and robust disclosure. * * * Full and adequate disclosure of information by the Enterprises regarding their financial conditions and risks is an

Continued

At present, the annual or quarterly financial statements prepared by a Bank are required to be consistent, in both form and content, with the combined financial statements prepared by OF for the entire Bank System.[60] The practices among the Banks, however, vary from Bank to Bank as to the level of detail that is provided by the annual and quarterly financial reports of the individual Banks. In conjunction with this rulemaking process, Finance Board staff has reviewed past quarterly and annual Bank disclosure documents of several Banks. As a result of that comparison, staff has concluded that the current individual Bank disclosures fall short, in certain respects, of the requirements for 1934 Act-compliant financial disclosures.

Areas where some of the Banks' current disclosures in annual reports were found by Finance Board staff to fall short of SEC-administered 1934 Act standards include:

• A description of Bank businesses and operations;

• The discussions of dividend payments, including why dividends are paid in the form of cash or stock, factors that could cause dividends to increase or decrease, and the interrelationship between advance rates and dividend payments;

• The discussions of selected financial data that highlight significant trends in the institution's financial condition and results of operations;

• Management discussion and analysis, particularly with respect to the risks associated with Bank mortgage assets;

• Qualitative and quantitative disclosures of interest rate, credit, and operational risks;

• Disclosures regarding accounting issues;

• Disclosures about officers and directors of the Banks, including disclosures about the compensation awarded to, earned by, or paid to directors and certain senior executive officers;

• Evaluations of the effectiveness of disclosure controls and procedures, or internal controls and procedures;

• CEO and CFO certifications as to the accuracy of the content of the Bank's annual report, the effectiveness of disclosure controls and procedures, and any deficiencies in internal controls and procedures; and

• Disclosures of certain accounting-related fees and services.

The final rule adopted by the Finance Board will lead to the elimination of these deficiencies, resulting in an increase in both the quality and quantity of individual Bank disclosures.

In addition to facilitating the Finance Board's efforts to ensure the safety and soundness of the Banks through increased market discipline, disclosures by the Banks that are consistent with industry standards will help the Finance Board in its efforts to ensure that the Banks remain able to raise funds in the capital markets. When issuing COs in the debt markets, the Banks compete primarily against the other two housing GSEs, Fannie Mae and Freddie Mac. As noted previously, both Fannie Mae and Freddie Mac have agreed to register their stock with the SEC under the 1934 Act. Fannie Mae has already done so, and Freddie Mac has stated that it will do so after it resolves certain accounting matters. Thus, unless the Finance Board requires the Banks to enhance their disclosures, once Freddie Mac has registered with the SEC, the Banks will be the only housing GSEs that are competing for funds in the capital markets with financial disclosures that are not subject to SEC scrutiny under the 1934 Act.

This may have negative effects in several ways. First, member interest in holding Bank stock may be diminished. Members of a Bank must hold a certain level of Bank stock, with the amount of stock that must be purchased determined by the capital plan of each Bank.[61] However, many Banks permit members to buy and hold "excess" stock, which is stock beyond what is required to remain a member of, or to do business with, the Bank. Members may be more reluctant to purchase or hold Bank "excess" stock if they conclude that they lack adequate information about the Bank issuer.

Second, since Bank membership is now voluntary,[62] the attractiveness of holding Bank stock may be adversely affected by a member's inability to obtain information that permits it to evaluate fully its investment. The change to all-voluntary membership increases the importance of disclosure in maintaining member confidence and thereby in maintaining adequate Bank capitalization.

Moreover, a perception, right or wrong, by the capital markets that non-SEC reviewed disclosures about the Bank System are less complete than are the disclosures of Fannie Mae and Freddie Mac also may adversely affect the ability of the Bank System to compete with the other housing GSEs for funding. As described more fully in section I.C.1, above, OF currently prepares combined disclosures based on information provided to it by the 12 Banks. The quality of the disclosures made by OF depends, therefore, on the quality of the information it receives from each of the Banks.[63]

Whether the prospective disparity between the quality of the disclosures provided by Fannie Mae and Freddie Mac and the Banks, respectively, is apt to affect significantly the ability of the Banks to raise funds in the capital markets is difficult to quantify, especially before the fact. By requiring the Banks to publish financial disclosures that are equivalent to those provided by their principal competitors, the Finance Board is eliminating the possibility that the Banks' access to the capital markets will be disadvantaged because of any perceived differences in the quality of their financial disclosures.

3. Benefits of Registration With the SEC Versus Registration With the Finance Board

Many of the commenters raised questions about the appropriateness of requiring registration by the Banks with

important part of the OFHEO's supervisory program. Full disclosure enhances market discipline."). 68 FR at 16715, 16716 (footnotes omitted).

[60] *See* 12 CFR 989.4. OF prepares the combined annual and quarterly financial statements for all twelve of the Banks, the scope, form, and content of which must be consistent with the requirements of SEC Regulations S–K and S–X.

[61] In the case of the four Banks that have not implemented their new capital plans, the amount of stock that members must hold is determined by the Bank Act rules that applied before they were amended by the GLB Act.

[62] Both before and after its amendment by the GLB Act, section 6 of the Bank Act required members to buy and hold stock to capitalize the Bank. *See* 12 U.S.C. 1426. Prior to the GLB Act amendments, section 6 set uniform stock purchase requirements applicable to members of each Bank. The GLB Act changed the Bank Act by requiring each Bank to adopt stock purchase requirements for its members in its capital plan. In addition, the GLB Act made membership in the Bank System voluntary for all members when it removed provisions from section 5(f) of the Home Owners' Loan Act that required a federal savings association to become a member of and maintain membership in the Bank district in which it maintained its principal place of business. GLB Act sec. 603.

[63] OF would not be required under the final rule to register a class of securities with the SEC and, therefore, would not be subject to SEC oversight. OF is a joint office of the 12 Banks, and was established to facilitate the issuing and servicing of the COs of the Banks. OF, like the Banks, is regulated by the Finance Board. As recognized by the SEC, because of the structure of the Bank System, there is no issuer tied to the Bank System Combined Reports and, therefore, no issuer to register with the SEC. *See* Beller Testimony, at 7. However, Finance Board regulations require that the Reports prepared by OF be consistent with SEC Regulations S–K and Regulation S–X in scope, form, and content generally. *See* 12 CFR 985.6(b)(1). These Reports are to be filed with, and reviewed by, the Finance Board. The SEC has requested the opportunity to review the Reports and provide the Finance Board with whatever comments the SEC may have, and the Finance Board intends to provide the SEC with this opportunity.

the SEC. These commenters noted that the Finance Board has a much better understanding of the Banks' business than does the SEC and would be better able to tailor disclosure requirements in a manner that will yield the most appropriate disclosures from the Banks. Commenters proposed that the Finance Board establish a disclosure regime modeled on section 12(i) of the 1934 Act, which requires various depository institutions to file their 1934 Act disclosure documents with their respective primary Federal banking regulatory agencies.[64] The commenters suggested that, because the SEC's emphasis is on investor protection while the Finance Board's emphasis is on the Banks' safety and soundness, registration with the SEC risks subjecting the Banks to conflicting regulatory directives. These commenters cited a disagreement in 1998 between the SEC and bank regulators over the appropriate treatment of a financial institution's loan loss reserves as an example of the problems that may arise.

After carefully considering the benefits and disadvantages of requiring disclosures to be filed with the SEC as opposed to the Finance Board, the Finance Board has determined that registration with the SEC is appropriate, for the reasons set forth below.

a. The SEC is the nation's functional disclosure regulator. As a matter of national policy, Congress has designated the SEC as the securities disclosure authority. Since its creation in 1934, the SEC has been at the forefront of investor protection and is generally recognized as significantly contributing to the integrity of the United States securities markets. The rules and regulations that form the SEC's disclosure system are widely recognized as establishing the best practices for disclosure, both domestically and internationally.

SEC staff is the nation's expert in the interpretation of disclosure and accounting rules. This is especially important in light of the changes in recent years in Bank activities, and the resulting increase in the complexity and sophistication of the Banks' accounting and financial statements. Furthermore, new FASB statements on reporting requirements, which will result in more comprehensive and detailed disclosures by the Banks, have given rise to interpretive complexities with regard to accounting and financial reporting. The SEC staff has the extensive accounting expertise required to review these types of disclosures.

b. While improved disclosure likely would mean greater transparency and more effective market discipline irrespective of who administers the disclosure regime, only Bank disclosures held to the same standards required of Fannie Mae, Freddie Mac, and other competitors for funding will enable investors to evaluate potential investments without concern that the information they are reviewing may differ due to inconsistent standards applied from one agency to the next. Investors in equity and debt securities have become familiar with disclosure documents filed with the SEC. Disclosures that diverge from what investors have come to expect would make it difficult for investors to make meaningful comparisons between the Banks, the other housing GSEs, and other companies seeking investors.

Departure from the standard practices followed by other market participants—including Fannie Mae and Freddie Mac—could lead the markets to draw negative inferences no matter how unwarranted. Only by registering with the SEC, and therefore submitting to SEC review, will the Banks be able to declare unambiguously that Bank disclosures comply with 1934 Act standards.

c. The unique characteristics of the Bank System can be accommodated by the SEC disclosure regime. The Finance Board recognizes that the Banks are different from virtually every other SEC registrant because they are cooperatives and they issue debt on a joint and several basis. However, the SEC has, as a result of extensive conversations with Bank representatives, demonstrated a willingness and ability to accommodate the Banks' unique status where appropriate.[65]

d. The SEC effectively coordinates its actions with other regulators. For instance, the SEC is the regulator responsible for reviewing 1934 Act disclosures of bank holding companies in the United States. The Federal Reserve Board (FRB) is the regulator responsible for the safety and soundness supervision of bank holding companies. In reviewing the coordination of the FRB's and SEC's roles, respectively, we found no instance of significant costs due to regulatory overlap between the two agencies. SEC officials have indicated that it is the SEC's operating policy to contact a registrant's primary regulator before taking action, including public release of information on an SEC enforcement action. SEC officials also have indicated that in such instances the primary regulator often is aware of the underlying issues through its examination program.

Bank supervision and disclosure review are independent, but complementary, missions. Enhanced disclosures, on a par with disclosures in other businesses, including the other housing GSEs, should help to promote safety and soundness. As previously discussed, the market discipline imposed by debt and equity investors on the operations of financial institutions has come to be viewed as an important complement to minimum capital requirements and the supervisory review process in ensuring the safe and sound operation of a financial institution.[66] Adequate and consistent disclosure is an important element in achieving market discipline since it is through such disclosure that market participants gain access to information on the risks faced by the institution in question. Critical to that process is the ability to compare information across similar institutions at a point in time and over time.

An effective structure for protecting the safety and soundness of the Bank System and the interests of investors in Bank debt and equity securities requires a regime in which the Finance Board, as safety and soundness regulator, is not the final arbiter for accounting and disclosure standards for the Banks. The principal responsibility of the Finance Board is to ensure that the Banks operate in a financially safe and sound manner and to keep any unsafe and unsound practices from creating unsafe and unsound conditions among the Banks. At the same time, the principal responsibility of the SEC is to ensure consistent and accurate disclosures for the benefit of debt and equity investors. The SEC is best able to ensure that the disclosures of the Banks are appropriately consistent with and on a par with those of other SEC registrants. This point was made in a "Joint Report on the Government Securities Market," prepared in 1992 by the Department of Treasury, the SEC, and the FRB.

While issues like the one noted by the commenters may arise where the SEC and the Finance Board disagree on the appropriate resolution of a particular issue, there is no reason to assume that these issues will be insurmountable. Indeed, in the one example provided concerning the appropriate treatment of loan loss reserves, the SEC and the bank

[64] As previously noted, section 12(i) explicitly assigns to the respective Federal banking regulatory agencies responsibility and authority to perform this function. The Finance Board and the Banks are not listed in section 12(i).

[65] For a more detailed discussion of the unique issues presented by the Bank System and the manner in which the SEC intends to address those issues, *see* section II.B.5, below.

[66] *See, e.g.*, Basel II.

regulator were able to resolve the issue and, in so doing, developed a better understanding of each other's respective interests.

e. SEC administration of Bank disclosures could be achieved quickly. The SEC disclosure standards are well established, and the SEC has the personnel in place to administer and enforce those standards on the Banks. A disclosure regime administered and enforced by the SEC could be implemented quickly, without the need for additional staff, and without a direct charge to the Banks. Finance Board staff would not be able to match the SEC staff's background or its access to comparative information. Disclosure review carried out by the Finance Board would likely take longer to implement as the Finance Board hired additional, highly expert staff. Moreover, regardless of how expert the Finance Board staff would become with 1934 Act disclosure standards, the limited universe subject to their review would make it difficult for them to obtain the depth and breadth of experience of SEC staff.

4. Costs of SEC Registration

A number of commenters cited a study commissioned by the Banks and prepared by First Manhattan Consulting Group (FMCG Study),[67] which attempted to assess the potential economic costs and benefits of requiring Bank registration of a class of securities with the SEC. The FMCG Study concluded that the Banks' compliance, liquidity, and funding costs under an SEC-administered disclosure regime could be significantly higher than comparable costs under a Finance Board-administered disclosure regime.

The Finance Board has reviewed and evaluated the FMCG Study and, for the reasons discussed below, has determined that the FMCG Study's conclusions are unfounded. While improving their level of disclosure from current levels to 1934 Act disclosure standards would increase the Banks' overall compliance costs, those costs would not be higher under an SEC-administered disclosure regime than under a Finance Board-administered disclosure regime. In addition, there is no evidence that the Banks' liquidity and funding costs under an SEC-administered disclosure regime would be higher than those under a Finance Board-administered disclosure regime.

a. *Compliance Costs.* Given that any disclosure regime instituted by the Finance Board would be designed to achieve parity with that of the SEC, there likely would be no additional compliance costs to the Banks under the SEC-administered disclosure regime stemming from the preparation and submission of the relevant documents. In fact, the compliance costs of SEC-administered registration are likely to be somewhat lower than would be the costs of filing with the Finance Board. As previously discussed, the SEC has the resources to review Bank disclosures, unlike the Finance Board. The SEC does not currently charge a filing fee for basic 1934 Act periodic disclosure documents, whereas the Finance Board would recover its increased costs of implementing a 1934 Act-compliant disclosure regime through higher assessments on the Banks. Thus, the costs of an SEC-administered disclosure regime compared to the costs of one administered by the Finance Board are likely to be somewhat lower for the Banks.

Compliance costs would be higher under an SEC-administered disclosure regime if (i) disclosures to the Finance Board would be less robust than what would be required by the SEC, or (ii) the Finance Board would review the disclosures and follow up on issues with less vigor (or at least a greater willingness to sanction selective non-disclosure) than would the SEC. Neither of these outcomes would be true if Banks were to register with the Finance Board, but, even if they were, they would simply serve to underscore the appropriateness of registration with the SEC.

b. *Liquidity Costs.* The FMCG Study contended that the Banks could face significantly higher liquidity costs under an SEC-administered regime than a Finance Board-administered regime, because SEC registration would increase the possibility of a future disruption in Bank System debt issuance, thereby requiring the Banks to substantially increase their liquidity holdings. The FMCG Study conclusions are premised on the assumption that SEC registration will cause investors to focus more on Bank-level events that are not material on a Bank System-wide level. The FMCG Study concludes that, as a result, it is reasonable to assume an anticipated funding disruption of 30 to 60 days and a mixed strategy of adding more liquid assets and purchasing liquidity back-up facilities.

However, the FMCG Study estimated additional liquidity costs based on worst-case scenarios, not expected outcomes, and the estimates make no reference to the likelihood that the worst-case scenarios would ever be realized. The FMCG estimates are little more than conjecture and apparently are based on an unfounded assumption that the SEC would respond more rigorously to disclosure issues than would the Finance Board. Moreover, the Finance Board is unconvinced that funding sources will be unable or unwilling to distinguish issues arising at a particular Bank from the combined condition of the 12 Banks. Neither the FMCG Study nor any other comment disagrees with the benefits of enhanced disclosure by the Banks. To suggest, as the FMCG Study does, that the Banks will be disadvantaged compared to Freddie Mac and Fannie Mae because the latter two GSEs disclose only those events that are material to their nationwide operations is inconsistent with the stated support by the commenters for enhanced disclosure at the Bank level. Thus, the Finance Board has determined that the FMCG Study's conclusions concerning the likely increase in liquidity costs when comparing the disclosure alternatives are unpersuasive.

Even assuming that SEC registration will result in a greater need for liquidity than would be the case if registration were with the Finance Board, the Finance Board notes that the Banks already maintain substantial liquidity. Finance Board staff analysis has concluded that aggregate Bank System liquidity is sufficient for a period of interrupted market access as long as 30 days, and may be sufficient for even longer periods. Thus, there is ample liquidity in the Bank System to accommodate the disruptions to market access that the FMCG Study has hypothesized could result as a result of SEC registration.

c. *Funding Costs.* The FMCG Study contended that the Banks could face substantially higher funding costs under an SEC-administered regime than under a Finance Board-administered regime, because SEC registration may diminish the market's perception of the GSE status of the Banks.[68]

The Finance Board is unconvinced that SEC registration necessarily will lead to increased funding costs due to a diminution in the Banks' status as GSEs. As the FMCG Study acknowledges, Fannie Mae's debt spreads compared to Treasury obligations improved slightly after it registered with the SEC. Finance Board staff analysis of bond spread data during

[67] *See* Study entitled "Potential Costs Related to the SEC Registration of the FHL Banks' Stock," dated October 15, 2003.

[68] The FMCG Study also noted that several accounting issues may arise as a result of SEC registration that are, in the words of FMCG, "red herring" in nature but which may nevertheless raise investor concerns. The accounting issues noted in the FMCG Study have been addressed by the SEC. *See* Beller Testimony.

the period surrounding Fannie Mae's SEC registration indicated there was no discernible effect on spreads. While there may be many reasons for these findings, one possibility is that the markets found the newly disclosed information slightly better than they expected or that the increased market discipline and regulatory scrutiny inherent in SEC oversight led the market to view Fannie Mae's debt more favorably.

Whether enhanced disclosures will affect funding costs will depend on the disclosure. It is possible that funding costs will decrease, either because investors are reassured by the availability of disclosures that meet the same level of scrutiny that other companies face or because there may be unfounded concerns that are allayed through better disclosure.

Regardless of the effect on funding costs, the Finance Board takes issue with any suggestion that it is preferable to withhold information that may cause concern among funding sources. The responsiveness of funding costs to favorable or unfavorable information is exactly the type of market discipline that financial transparency is meant to produce. It likely will encourage the Banks to manage the risks in their portfolios proactively to maintain low funding costs, rather than to manage them reactively in response to pressure from the Finance Board.

5. Resolution of Operational Issues

Several commenters did not oppose registration with the SEC, but stated that the registration date should be delayed until operational issues related to the unique structure of the Banks are resolved with the SEC. Several commenters recommended that the Finance Board and the SEC enter into a Memorandum of Understanding (MOU) to resolve the operational issues, and indicated their preferred outcome with respect to those issues. These commenters requested that the MOU relieve the Banks of the registration requirement in the event that the positions reached by the SEC change or if the SEC takes an action that impairs the Banks' access to the capital markets. Some commenters also recommended that the Banks be parties to, or third-party beneficiaries of, the MOU.

Examples of operational issues cited by commenters include: the accounting treatment of Bank joint and several liabilities; the accounting treatment of the Banks' Resolution Funding Corporation (REFCORP) payments; the characterization of Bank stock as "puttable" or "redeemable;" the short-cut hedge accounting treatment for swaps associated with swapped callable debt; the preparation of Bank System Combined Reports rather than reports that consolidate the financial statements of the 12 Banks; the requirement to make the certifications required by the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley);[69] the requirement to prepare annual meeting proxies; and the requirement that certain member stockholders file an insider trading form with the SEC each time the stockholder conducts a transaction in the registrant's stock.

SEC staff testified recently that many of these issues have been resolved. For instance, the SEC does not object to the treatment of REFCORP payments as the equivalent of a tax, with the result being that the capitalized obligation would not appear on a Bank's balance sheet. The SEC also has agreed that a Bank's stock, though "puttable" (meaning that the stock is, as a general matter, redeemable), may be treated as equity by the Bank.[70] Moreover, the SEC will permit each Bank to include on its balance sheet as long-term indebtedness only the amount of COs for which that Bank is the primary obligor.[71] SEC staff has advised that certain other disclosure requirements and changes to the Banks' existing accounting policies would not be imposed on the Banks if the Banks were to register, and has indicated that it would continue to work with the Banks to determine the appropriateness of certain disclosures under the 1934 Act.[72] The Finance Board understands that the SEC will issue to Banks a "No Action" letter addressing various disclosure issues as well as an interpretive letter addressing a number of issues, including those discussed in the Beller Testimony.

In its deliberations leading up to adoption of the final rule, the Finance Board has explored with the SEC whether the SEC's and the Banks' resolution of the various accounting and disclosure issues that were raised because of the cooperative nature of the Bank System would be changed unilaterally by the SEC. In conversations involving representatives of the SEC and the Finance Board, SEC staff has stated that the SEC has never rescinded a No Action letter, and that, absent a change in the facts or applicable law, recipients of such a letter may rely on it even if the SEC were to reach a different conclusion when considering the issue at a later time. In addition, the SEC staff stated that it will communicate with the Finance Board before changing any of the SEC's views as stated in the Beller Testimony and reiterated in the letter from the SEC to the Finance Board dated June 1, 2004. The Finance Board has adopted this final rule relying on the SEC's staff representations concerning the effectiveness of No Action letters as well as the statements made by the SEC in the Beller Testimony and subsequent communications with the Finance Board. The Finance Board will consult with the SEC to achieve a satisfactory resolution of any issue that arises that interferes with the Finance Board's authority under the Bank Act.

Commenters proposed varying dates that would trigger the requirement to register, including: 2005; the filing date for the 2005 annual report (2006); 18 months from the effective date of the final rule; and 18 months from the later of (i) the effective date of the final rule, (ii) the effective date of an MOU on operational issues, or (iii) the resolution of the relevant operational issues. Commenters stated that if these unique accounting, regulatory, and economic issues were not resolved before the Banks are required to register with the SEC, the Banks' access to the capital markets could be disrupted or delayed.

Given the successful resolution of many of the issues raised by commenters with the SEC and the significant period of time that has elapsed since the Finance Board began considering this issue, the Finance Board believes that it is appropriate to set a date certain in the final rule by which registration with the SEC is to be effective. Based on information obtained from the SEC staff concerning the steps required to have an effective registration of a class of equity securities under the 1934 Act, the Finance Board has

[69] Pub. L. 107–204.

[70] SEC staff noted, however, that the SEC will continue to have a dialogue with the Banks on the proper accounting treatment in the event that a stockholder puts the stock to a Bank. Beller Testimony at 7.

[71] *See* Beller Testimony at 6–7.

[72] Congress has assigned to the SEC the authority and responsibility to prescribe the methods to be followed in the preparation of financial accounts and the form and content of financial statements to be filed under the securities laws. *See, e.g.*, sections 7, 19(a), and Schedule A, items (25) and (26) of the 1933 Act (15 U.S.C. 77g, 77s(a), 77aa(25) and (26)); and sections 3(b), 12(b), and 13(b) of the 1934 Act (15 U.S.C. 78c(b), 78*l*(b), and 78m(b)). Subject to SEC oversight, the Financial Accounting Standards Board (FASB) has been delegated the authority to set accounting standards to be used by public companies. *See* SEC Policy Statement Reaffirming the Status of FASB as a Designated Private-Sector Standard Setter (Release Nos. 33–8221; 34–47743; IC–26028; FR–70), 68 FR 23333 (May 1, 2003). The Banks' disclosures are required to satisfy the generally accepted accounting standards established by FASB. Accordingly, all Finance Board regulatory interpretations concerning accounting issues are superceded by SEC and FASB pronouncements on point.

determined that it is appropriate for each Bank to file a registration statement under the 1934 Act with the SEC by no later than June 30, 2005, and have the registration effective no later than August 29, 2005. These dates may be extended if the Finance Board determines, upon a written request by one or more of the Banks, that good cause exists for extending the deadline for registration.

Some commenters noted that bills are pending in Congress that could restructure the Bank System's regulatory regime, and suggested that the Finance Board delay action on a final rule until the legislative uncertainties are resolved. However, the Finance Board believes that it has the duty to fulfill the responsibilities entrusted to it under the Bank Act, and, unless and until those responsibilities are changed by Congress, the Finance Board must continue to conduct business accordingly. It is in furtherance of those duties that the Finance Board adopts this final rule.

A few commenters suggested that the Finance Board postpone acting on the proposed SEC registration regulation until each Bank completes its conversion to a new capital plan, in accordance with the provisions of the GLB Act. The Finance Board recognizes that Banks in transition may have some unique issues to address in their registration filings. However, the Finance Board believes that it is best to realize the benefits of registration, as outlined above, as soon as possible, without waiting for the remaining Banks to convert. The Finance Board notes that the availability of SEC-reviewed disclosure documents prior to a capital plan conversion may assist Bank members in understanding issues related to the implementation of a new capital plan by their Bank.

III. Analysis of Final Rule

In light of the preceding discussion, the Finance Board has determined to adopt in substantially similar form the proposed rule as a final rule. The specific provisions of the final rule, which amends existing § 900.3 and adds a new part 998, are described in the following sections. These provisions, and substantive changes made to language contained in the proposed rule, are discussed below.

Part 900—General Definitions Applying to All Finance Board Regulations

Section 900.3

The final rule amends § 900.3 of the Finance Board's regulations, 12 CFR 900.3, to include the following three additional definitions of terms related to securities disclosures that are used in the final rule: "GLB Act," meaning the Gramm-Leach-Bliley Act (Pub. L. 106–102 (1999)); "SEC," meaning the United States Securities and Exchange Commission; and "1934 Act," meaning the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*). The Finance Board received no comments on the proposed addition of these three defined terms to § 900.3, and has adopted them as proposed.

Part 998—Registration of Federal Home Loan Bank Equity Securities

Section 998.1—Purpose

Section 998.1 of the proposed rule noted that the purpose of new part 998 is to require each Bank to prepare and publicly distribute certain financial and other disclosures. It also noted that the disclosure requirements set forth in part 998 did not limit or restrict the Finance Board's ability to act pursuant to its safety and soundness authority.

The final rule retains a description of the purposes of the rule, but amplifies on that description by stating that the purposes of part 998 are to enhance the quality of the financial disclosures provided by each Bank, to promote a greater degree of consistency and uniformity of such disclosures from Bank to Bank, to provide a greater degree of transparency regarding the financial condition of each Bank, and to conform the disclosure practices of the Banks to those of other financial institutions who raise funds in the global debt markets. The Finance Board believes that this is a more accurate and complete statement of the purposes of the securities disclosure regulation.

The discussion concerning the Finance Board's continued authority to require Banks to take steps in addition to those required by part 998, including the authority to require additional disclosures as appropriate, has been set out in a separate § 998.3, as discussed below.

Section 998.2—Registration and Periodic Disclosures

Proposed § 998.2 contained four requirements. First, it required each Bank to prepare and make public disclosures relating to financial condition, results of operations, trends or uncertainties affecting its business, and management's assessment of the Bank's business and financial condition. Second, it required each Bank to satisfy the disclosure requirement by subjecting itself to the 1934 Act's periodic disclosure regime. Third, the proposed rule required each Bank to subject itself to the 1934 Act's periodic disclosure requirements by registering a class of securities with the SEC within 120 days of the adoption of a final rule by the Finance Board. Lastly, the proposed rule required each Bank to provide to the Finance Board, on a concurrent basis, copies of all disclosure documents filed with the SEC, unless otherwise directed by the Finance Board.

The final rule retains the basic requirements set out in the proposed rule, but revises them so that they are now set out more clearly. Paragraph (a)(1) of § 998.2 states that each Bank shall file a registration statement by no later than June 30, 2005 to register a class of its equity securities pursuant to the provisions of section 12(g)(1) of the 1934 Act. Each Bank shall ensure that its registration statement becomes effective as provided in section 12 no later than August 29, 2005. This will require each Bank to file a Form 10 with the SEC and have the Form 10 become effective as contemplated by 1934 Act rule 12b–6. A Bank that files a Form 10 and then withdraws it will not be deemed in compliance with this requirement. Thereafter, Banks will be required to maintain such registration in effect at all times. Paragraph (a)(2) of § 998.2 states that the Finance Board may by order extend the registration date for one or more Banks if it determines, based on factors presented in a written request to the Finance Board, that good cause exists to do so.

Paragraph (b) requires Banks to comply with periodic disclosure requirements under the 1934 Act and disclose any other information required by SEC rules, regulations, or interpretations. These requirements will be modified to the extent relief is granted to the Banks by the SEC in No Action letters or interpretive letters.

Paragraph (c) sets forth the general requirement that Banks provide to the Finance Board on a concurrent basis copies of all disclosure documents that are filed with the SEC.

Section 998.3—Reservation of Authority

Section 998.1(b) of the proposed rule explicitly retained the authority of the Finance Board to exercise any other authority that has been vested in it by Congress, specifically including the authority to require additional disclosures as appropriate. That reservation of authority has been relocated to a new § 998.3 and revised to improve the rule's clarity. As set forth in the final rule, the requirements of part 998 do not diminish, or otherwise restrict the ability of the Finance Board to exercise, any and all authority conferred by the Bank Act to ensure that the Banks operate in a financially safe and sound manner, that they carry out their housing finance mission, and that they remain adequately capitalized and able to raise funds in the capital markets. Nor do the requirements of part 998 diminish or otherwise restrict the Finance Board's authority to supervise the Banks, to conduct examinations, to require reports and other disclosures, and to enforce compliance with applicable laws, rules, orders or agreements.

IV. Regulatory Analyses

A. Paperwork Reduction Act

One commenter stated that the Finance Board failed to comply with the requirements of the Paperwork Reduction Act of 1995 (PRA) by failing to submit the disclosure requirements in the proposed rule to the Office of Management and Budget (OMB) for review.[73] However, as noted in the SUPPLEMENTARY INFORMATION section of the proposed rule, the proposed rule does not contain any collections of information as defined by the PRA, nor does the final rule. Under the OMB's implementing PRA regulation, the term "collection of information" includes the collecting of information from instrumentalities of the United States only if the results are to be used for general statistical purposes.[74] Although the Banks are instrumentalities of the United States, the required disclosures will not be used for general statistical purposes, and thus they do not constitute a "collection of information" subject to the PRA. Consequently, the Finance Board has not submitted any information to the OMB for review.

B. Regulatory Flexibility Act

The final rule will apply only to the Banks, which do not come within the meaning of "small entities," as defined in the Regulatory Flexibility Act (RFA).[75] Therefore, in accordance with section 605(b) of the RFA,[76] the Finance Board hereby certifies that the final rule will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 12 CFR Parts 900 and 998

Credit, Federal home loan banks, Financial disclosure, Government-sponsored enterprises, Records, Reporting and recordkeeping requirements, and Securities disclosure.

[73] *See* 44 U.S.C. 3501 *et seq.*

[74] *See* 5 CFR 1320.3(c)(3).

[75] *See* 5 U.S.C. 601(6).

[76] 5 U.S.C. 605(b).

■ Accordingly, the Finance Board hereby amends title 12, chapter IX, Code of Federal Regulations, as follows:

PART 900—GENERAL DEFINITIONS APPLYING TO ALL FINANCE BOARD REGULATIONS

■ 1. The authority citation for part 900 continues to read as follows:

Authority: 12 U.S.C. 1422b(a).

■ 2. Amend § 900.3 by adding the following three definitions in alphabetical order:

§ 900.3 Terms relating to other entities and concepts used throughout 12 CFR chapter IX.

* * * * *

"GLB Act" means the Gramm-Leach-Bliley Act (Pub. L. 106–102 (1999)).

* * * * *

"SEC" means the United States Securities and Exchange Commission.

* * * * *

"1934 Act" means the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*).

* * * * *

■ 3. Add Subchapter M (part 998) to title 12, chapter IX, to read as follows:

Subchapter M—Federal Home Loan Bank Disclosures

PART 998—REGISTRATION OF FEDERAL HOME LOAN BANK EQUITY SECURITIES

Sec.

Authority: 12 U.S.C. 1422a(a)(3), 1422b(a)(1).

§ 998.1 Purpose.

The purposes of this part are to enhance the quality of the financial disclosures provided by each Bank, to promote a greater degree of consistency and uniformity of such disclosures from Bank to Bank, to provide a greater degree of transparency regarding the financial condition of each Bank, and to conform the disclosure practices of the Banks to those of other financial institutions who raise funds in the global debt markets.

§ 998.2 Registration and periodic disclosures.

(a) *Registration.* (1) Each Bank shall file a registration statement by no later than June 30, 2005 to register a class of its equity securities pursuant to the provisions of section 12(g)(1) of the 1934 Act. Each Bank shall ensure that its registration statement becomes effective as provided in section 12 no later than August 29, 2005.

(2) Notwithstanding paragraph (a)(1) of this section, the Finance Board may by order extend the registration date for one or more Banks if it determines, based on factors presented in a written request to the Finance Board, that good cause exists to do so.

(b) *Periodic disclosures.* Consistent with the registration required pursuant to paragraph (a) of this section, each Bank, after registering a class of equity securities with the SEC, shall comply with the periodic disclosure requirements of the 1934 Act by preparing and filing with the SEC such annual, quarterly, and current reports, as well as any other materials required pursuant to SEC rules, regulations, or interpretations, including those related to audited financial statements, as may be required by the SEC under the 1934 Act.

(c) *Submission to Finance Board.* Unless otherwise directed by the Finance Board, each Bank shall provide to the Finance Board on a concurrent basis copies of all disclosure documents filed with the SEC.

§ 998.3 Reservation of authority.

The requirements of this part do not diminish, or otherwise restrict the ability of the Finance Board to exercise, any and all authority conferred by the Bank Act to ensure that the Banks operate in a financially safe and sound manner, that they carry out their housing finance mission, and that they remain adequately capitalized and able to raise funds in the capital markets. Nor do the requirements of part 998 diminish or otherwise restrict the Finance Board's authority to supervise the Banks, to conduct examinations, to require reports and other disclosures, and to enforce compliance with applicable laws, rules, orders or agreements.

Dated: June 23, 2004.

By the Board of Directors of the Federal Housing Finance Board.

Alicia R. Castaneda,

Chairman.

[FR Doc. 04–14696 Filed 6–28–04; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2002–NM–297–AD; Amendment 39–13691; AD 2004–13–09]

RIN 2120–AA64

Airworthiness Directives; Bombardier Model DHC–8–301, –311, and –315 Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Bombardier Model DHC–8–301, –311, and –315 airplanes. This AD requires determining the modification number of the angle of attack (AOA) sensor vanes; testing the movement of the affected vanes to evaluate sticking against both the upper and the lower vane travel end stops; and corrective action, if necessary. This action is necessary to prevent an incorrect AOA indication to the stall warning system in flight, which could result in an inadvertent stall and consequent loss of control of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 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; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Ezra Sasson, Aerospace Engineer, Systems and Flight Test Branch, ANE–172, New York Aircraft Certification Office, FAA, 1600 Stewart Avenue, suite 410, 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–8–301, –311, and –315 airplanes was published in the **Federal Register** on April 26, 2004 (69 FR 22461). That action proposed to require determining the modification number of the angle of attack (AOA) sensor vanes; testing the movement of the affected vanes to evaluate sticking against both the upper and the lower vane travel end stops; and corrective action, if necessary.

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

We have determined that air safety and the public interest require the adoption of the rule as proposed.

Cost Impact

We estimate that 57 airplanes of U.S. registry will be affected by this AD, that it will take approximately 1 work hour per airplane to accomplish the proposed inspection to determining the modification letter, 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 $3,705, or $65 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:

2004–13–09 Bombardier, Inc. (Formerly de Havilland, Inc.): Amendment 39–13691. Docket 2002–NM–297–AD.

Applicability: Model DHC–8–301, –311, and –315 airplanes, serial numbers 100 through 583, inclusive; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent an incorrect angle of attack (AOA) indication to the stall warning system in flight, which could result in an inadvertent stall and consequent loss of control of the airplane, accomplish the following:

Service Bulletin References

(a) The term "service bulletin," as used in this AD, means the Accomplishment Instructions of Bombardier Alert Service Bulletin A8–27–94, Revision 'A', dated February 5, 2002.

Note 1: Bombardier Alert Service Bulletin A8–27–94, Revision 'A', references Rosemount Aerospace Alert Service Bulletin 0861CAB–27A–07, dated September 28, 2001, as an additional source of service information for testing the AOA sensors. The Rosemount service bulletin is included in the Bombardier service bulletin.

Inspection to Determine Modification

(b) Within 1,000 flight hours or 18 months after the effective date of this AD, whichever occurs first, inspect the right and left AOA sensor vanes to determine whether modification (MOD) 'J' has been incorporated. Instead of inspecting the sensors, a review of airplane maintenance records is acceptable if the MOD level of the sensor can be positively determined from that review. If MOD 'J' has been incorporated in both sensors, no further action is required by this paragraph.

Movement Tests

(c) For any AOA sensor vane that does not have MOD 'J' installed: Prior to further flight following the inspection required by paragraph (b) of this AD, do a movement test of the AOA sensor vane per the service bulletin.

(d) If the result of the movement test in paragraph (c) of this AD is less than 110 grams, repeat the movement test prior to the accumulation of 5,000 flight hours or 24 months after accomplishing the initial test, whichever occurs first. Do the test per the service bulletin.

Corrective Action

(e) If the result of any movement test in paragraph (c) or paragraph (d) of this AD is 110 grams or more, replace the AOA sensor vane with a reworked MOD 'J' sensor vane, per the service bulletin, at the applicable time in paragraph (e)(1), (e)(2), or (e)(3) of this AD.

(1) If the result of the movement test in paragraph (c) of this AD is between 110 and 169 grams inclusive, replace the sensor vane at the earlier of 1,000 flight hours, or 18 months after accomplishing the movement test in paragraph (c) of this AD.

(2) If the result of any repeat movement test in paragraph (d) of this AD is between 110 and 169 grams inclusive, replace the sensor vane at the earlier of 1,000 flight hours or 6 months after accomplishing the movement test in paragraph (d) of this AD.

(3) If the result of the movement test is 170 grams or more, replace the sensor vane within 5 days after the accomplishing the movement test in paragraph (c) or paragraph (d) of this AD.

Parts Installation

(f) As of the effective date of this AD, no person may install a sensor vane, part number 861CAB, on any airplane unless MOD "J" has been incorporated.

Reporting and Parts Modification

(g) Although the Rosemount service bulletin contains procedures for sending test findings to the manufacturer, and for sending removed parts to the manufacturer for modification, this AD does not require those actions.

Actions Accomplished Per Previous Release of Service Bulletin

(h) Actions accomplished before the effective date of this AD per Bombardier Alert Service Bulletin A8–27–94, dated October 25, 2001, are considered acceptable for compliance with the corresponding action specified in this AD.

Alternative Methods of Compliance

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

Incorporation by Reference

(j) Unless otherwise specified in this AD, the actions shall be done in accordance with Bombardier Alert Service Bulletin A8–27–94, Revision "A", dated February 5, 2002. 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; or at the FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, suite 410, Westbury, New York; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 2: The subject of this AD is addressed in Canadian airworthiness directive CF–2001–46, dated December 3, 2001.

Effective Date

(k) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14319 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–236–AD; Amendment 39–13690; AD 2004–13–08]

RIN 2120–AA64

Airworthiness Directives; Short Brothers Model SD3–60 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to all Short Brothers Model SD3–60 series airplanes. This AD requires inspection of the welded joints of the balance weight brackets for the left and right elevator trim tabs for cracking; repetitive inspections, as applicable; and corrective actions including the eventual replacement of all brackets, which constitutes terminating action for the repetitive inspections. This action is necessary to prevent the loss of the balance weight for the elevator trim tab, which could result in incorrect trim during takeoff and landing, and reduced controllability of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Short Brothers, Airworthiness & Engineering Quality, P.O. Box 241, Airport Road, Belfast BT3 9DZ, Northern Ireland. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–1175; fax (425) 227–1149.

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 all Short Brothers Model SD3–60 series airplanes was published in the **Federal Register** on April 22, 2004 (69 FR 21766). That action proposed to require inspection of the welded joints of the balance weight brackets for the left and right elevator trim tabs for cracking; repetitive inspections, as applicable; and corrective actions including the eventual replacement of all brackets, which would constitute terminating action for the repetitive inspections.

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

We have determined that air safety and the public interest require the adoption of the rule as proposed.

Cost Impact

We estimate that 42 airplanes of U.S. registry will be affected by this AD, that it will take approximately 12 work hours per airplane to accomplish the required inspections, and that the average labor rate is $65 per work hour. Based on these figures, the cost impact of this action on U.S. operators is estimated to be $32,760, or $780 per airplane.

It will take approximately 8 work hours per airplane to accomplish the replacement of the brackets. Required parts will cost approximately $632 per airplane. Based on these figures, the cost impact of this action on U.S. operators is estimated to be $48,384, or $1,152 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:

2004–13–08 Short Brothers PLC: Amendment 39–13690. Docket 2003–NM–236–AD.

Applicability: All Model SD3–60 series airplanes, certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent the loss of the balance weight for the elevator trim tab, which could result in incorrect trim during takeoff and landing, and reduced controllability of the airplane, accomplish the following:

Service Bulletin Reference

(a) The term "service bulletin," as used in this AD, means the Accomplishment Instructions of Short Brothers Service Bulletin SD360–55–20, dated June 26, 2003.

Initial Inspection

(b) Within 2 months after the effective date of this AD: Do a dye penetrant inspection for cracking in the welded joints of the balance weight brackets for the left and right elevator trim tabs, in accordance with the service bulletin.

Investigative and Corrective Actions if No Cracking Is Found

(c) If no cracking is found during the inspection required by paragraph (b) of this AD, do the actions required by paragraphs (c)(1) and (c)(2) of this AD at the applicable compliance times.

(1) Repeat the inspection required by paragraph (b) of this AD at intervals not to exceed 4,800 flight hours until the bracket is replaced per paragraph (c)(2) or (d) of this AD.

(2) Prior to the accumulation of 28,800 total flight hours, or within 6 months after the effective date of this AD, whichever occurs later: Replace any bracket that has not been replaced per paragraph (d) of this AD with a new bracket or with a serviceable bracket that has been inspected in accordance with paragraph (b) of this AD. Replace in accordance with the service bulletin. Replacement of the brackets constitutes terminating action for the repetitive inspections required by paragraph (c)(1) of this AD.

Corrective Actions if Any Cracking Is Found

(d) If any cracking is found during any inspection required by paragraph (b) or (c) of this AD: Before further flight, accomplish the applicable action in paragraph (d)(1) or (d)(2) of this AD in accordance with the service bulletin.

(1) For airplanes that have accumulated less than 28,800 flight hours and on which all cracking on brackets is less than 0.25 inch in length: Repair the affected bracket in accordance with Part B of the service bulletin (including the additional dye penetrant inspection of the repaired welded joint) and repeat the inspection required by paragraph (b) of this AD at intervals not to exceed 4,800 flight hours; or replace the bracket in accordance with paragraph (d)(2) of this AD. Replacement of the bracket constitutes terminating action for the repetitive inspections.

(2) For any airplane on which any cracking on a bracket is 0.25 inch in length or greater, and for any airplane that has accumulated 28,800 flight hours or more on which any cracking of any length is found on a bracket: Replace the affected bracket with a new bracket or with a serviceable bracket that has been inspected in accordance with paragraph (b) of this AD. Replacement of the bracket constitutes terminating action for the repetitive inspections required by paragraph (d)(1) of this AD.

Refitting

(e) Before further flight following any inspection per paragraphs (b) or (c) of this AD; or before further flight following repair or replacement of a bracket per paragraphs (c)(2) or (d) of this AD: Refit the balance weights, covers, and trim tabs, in accordance with the service bulletin. Where the service bulletin specifies to contact the manufacturer for disposition of certain conditions while refitting, obtain further disposition instructions from the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate; or the Civil Aviation Authority (CAA) (or its delegated agent).

Parts Installation

(f) As of the effective date of this AD, no person may install on any airplane a balance weight bracket unless the welded joint has been inspected in accordance with paragraph (b) of this AD.

Alternative Methods of Compliance

(g) In accordance with 14 CFR 39.19, the Manager, International Branch, ANM–116, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(h) Unless otherwise specified in this AD the actions shall be done in accordance with Short Brothers Service Bulletin SD360–55–20, dated June 26, 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 Short Brothers, Airworthiness & Engineering Quality, P.O.

Box 241, Airport Road, Belfast BT3 9DZ, Northern Ireland. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 1: The subject of this AD is addressed in British airworthiness directive 009–06–2003.

Effective Date

(i) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14321 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2001–NM–331–AD; Amendment 39–13692; AD 2004–13–10]

RIN 2120–AA64

Airworthiness Directives; Bombardier Model DHC–8–102, –103, –106, –201, –202, –301, –311, and –315 Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Bombardier Model DHC–8–102, –103, –106, –201, –202, –301, –311, and –315 airplanes, that requires rework/retrofit of the wardrobe shelf assembly. This action is necessary to prevent the wardrobe shelf and attached equipment separating from the attachment in the event of a hard landing, which could impede the egress of passengers in the event of an emergency evacuation. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 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; or at the FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, suite 410, Westbury, New York; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Leung Lee, Aerospace Engineer, Systems and Flight Test Branch, ANE–172, FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, Westbury, suite 410, New York 11590; telephone (516) 228–7309; 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–8–102, –103, –106, –201, –202, –301, –311, and –315 airplanes was published in the **Federal Register** on April 1, 2004 (69 FR 17113). That action proposed to require rework/retrofit of the wardrobe shelf assembly.

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

The FAA estimates that 18 airplanes of U.S. registry will be affected by this AD, that it will take approximately 20 work hours per airplane to accomplish the required actions, and that the average labor rate is $65 per work hour. Required parts will cost approximately $1,387 per airplane. Based on these figures, the cost impact of the AD on U.S. operators is estimated to be $48,366, or $2,687 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:

2004–13–10 Bombardier, Inc. (Formerly de Havilland, Inc.): Amendment 39–13692. Docket 2001–NM–331–AD.

Applicability: Model DHC–8–102, –103, –106, –201, –202, –301, –311, and –315 airplanes, serial numbers 452, 464, 490, 506, 508 through 531 inclusive, and 535; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent the wardrobe shelf and attached equipment separating from the attachment in the event of a hard landing, which could impede the egress of passengers in the event of an emergency evacuation, accomplish the following:

Rework/Retrofit

(a) Within 12 months after the effective date of this AD, rework/retrofit the wardrobe shelf assembly per the Accomplishment Instructions of Bombardier Service Bulletin 8–25–311, Revision 'B,' dated December 15, 2000.

(b) Rework/retrofit of the wardrobe shelf assembly accomplished before the effective date of this AD per Bombardier Service Bulletin 8–25–311, dated December 14, 1999; or Revision 'A,' dated February 8, 2000; is acceptable for compliance with the requirements of paragraph (a) of this AD.

Alternative Methods of Compliance

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

Incorporation by Reference

(d) Unless otherwise specified in this AD, the actions shall be done in accordance with Bombardier Service Bulletin 8–25–311, Revision 'B,' dated December 15, 2000. 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; or at the FAA, New York Aircraft Certification Office, 1600 Stewart Avenue, suite 410, Westbury, New York; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 1: The subject of this AD is addressed in Canadian airworthiness directive CF–2001–17, effective June 15, 2001.

Effective Date

(e) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14322 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2002–NM–208–AD; Amendment 39–13689; AD 2004–13–07]

RIN 2120–AA64

Airworthiness Directives; BAE Systems (Operations) Limited (Jetstream) Model 4101 Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to all BAE Systems (Operations) Limited (Jetstream) Model 4101 airplanes. This AD requires operators to determine the flight cycles accumulated on each component of the main landing gear (MLG) and the nose landing gear (NLG), and to replace each component that reaches its life limit with a serviceable component. This AD also requires operators to revise the Airworthiness Limitations section of the Instructions for Continued Airworthiness in the aircraft maintenance manual to reflect the new life limits. This action is necessary to prevent failure of certain components of the MLG and the NLG, which could result in failure of either or both landing gears, and consequent damage to the airplane and injury to passengers or crewmembers. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from British Aerospace Regional Aircraft American Support, 13850 Mclearen Road, Herndon, Virginia 20171. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–1175; fax (425) 227–1149.

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 all BAE Systems (Operations) Limited (Jetstream) Model 4101 airplanes was published in the **Federal Register** on March 5, 2004 (69 FR 10385). That action proposed to require operators to determine the flight cycles accumulated on each component of the main landing gear and the nose landing gear, and to replace each component that reaches its life limit with a serviceable component. That action also proposed to require operators to revise the Airworthiness Limitations section of the Instructions for Continued Airworthiness to reflect the new life limits.

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

We have determined that air safety and the public interest require the adoption of the rule as proposed.

Explanation of Change Made to the Proposed Rule

We have revised paragraph (a) the final rule to include BAE Systems (Operations) Limited Service Bulletin J41–05–001, Revision 3, dated January 9, 2004, as an additional appropriate source of service information for calculating the total accumulated flight cycles. In addition, we have revised paragraph (f) of the final rule to give operators credit for accomplishing the same calculation per two earlier revisions of Service Bulletin J41–05–001: Revision 1, dated April 10, 2001, Revision 2, dated March 15, 2002.

Cost Impact

We estimate that 57 airplanes of U.S. registry will be affected by this AD. It will take approximately 1 work hour per airplane to accomplish the required determination of the number of flight cycles, and 1 work hour per airplane to accomplish the required revision of the aircraft maintenance manual. 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 $7,410, or $130 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:

2004–13–07 BAE Systems (Operations) Limited (Formerly British Aerospace Regional Aircraft): Amendment 39–13689. Docket 2002–NM–208–AD.

Applicability: All Model Jetstream 4101 airplanes, certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent failure of certain components of the main landing gear and the nose landing gear, which could result in failure of either or both landing gears, and consequent damage to the airplane and injury to passengers or crewmembers, accomplish the following:

Determine Flight Cycles for Components

(a) Within 90 days after the effective date of this AD: Determine the number of flight cycles accumulated on each landing gear component listed in Table 1 and Table 2 of the Accomplishment Instructions of BAE Systems (Operations) Limited Service Bulletin J41–32–078, dated April 12, 2002. If there are no records or incomplete records for any component, establish the number of flight cycles in accordance with the Accomplishment Instructions of BAE Systems (Operations) Limited Service Bulletin J41–05–001, Revision 2, dated March 15, 2002; or Revision 3, dated January 1, 2004.

Note 1: BAE Systems (Operations) Limited Service Bulletin, J41–32–078 refers to BAE Systems (Operations) J41 Service Information Leaflet 32–15, Issue 1, dated February 15, 2002, as an additional source of service information for establishing the life limits of landing gear components and for tracking the accumulated life of each component.

Replace Components

(b) Except as provided by paragraph (c) of this AD, within 60 days after establishing the flight cycles per paragraph (a) of this AD: Replace any landing gear component that has reached the life limit determined by paragraph (a) of this AD, with a serviceable component per a method approved by either the Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA; or the CAA Civil Aviation Authority (CAA) (or its delegated agent). Doing the actions in chapter 32 of the applicable aircraft maintenance manual (AMM) is one approved method. Thereafter, replace any component that reaches its life limit prior to the accumulation of the applicable number of flight cycles shown in Table 1 and Table 2 of the Accomplishment Instructions of BAE Systems (Operations) Limited Service Bulletin J41–32–078, dated April 12, 2002.

(c) Any component for which the total accumulated life cycles has not been established, or that has exceeded its life limit, but has not yet been replaced per paragraph (b) of this AD, must be replaced within 72 months after the effective date of this AD, in accordance with BAE Systems (Operations) Limited Service Bulletin J41–32–078, dated April 12, 2002.

Revise Aircraft Maintenance Manual

(d) Within 30 days after the effective date of this AD: Revise the Airworthiness Limitations section of the Instructions for Continued Airworthiness of the Jetstream 4100 AMM to include the life limits of the components listed in Table 1 and Table 2 of the Accomplishment Instructions of BAE Systems (Operations) Limited Service Bulletin J41–32–078, dated April 12, 2002. This may be accomplished by inserting a copy of the service bulletin in the Airworthiness Limitations section of the Instructions for Continued Airworthiness until such time as a revision is issued. Thereafter, except as provided in paragraph (g) of this AD, no alternative replacement times may be approved for any affected component.

Parts Installation

(e) As of the effective date of this AD, no landing gear unit may be installed on any airplane unless the accumulated flight cycles of all components of that landing gear have been established per paragraph (a) of this AD, and any component that has exceeded its life limit has been replaced per paragraph (b) of this AD.

Actions Accomplished Per Previous Issue of Service Bulletin

(f) Calculations of total accumulated flight cycles accomplished per BAE Systems (Operations) Limited Service Bulletin J41–05–001, Revision 1, dated April 10, 2001; or BAE Systems (Operations) Limited Service Bulletin J41–05–001, Revision 2, dated March 15, 2002; are considered acceptable for compliance with the corresponding action specified in this AD.

Alternative Methods of Compliance

(g) In accordance with 14 CFR 39.19, the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(h) Unless otherwise specified in this AD, the actions shall be done in accordance with BAE Systems (Operations) Limited Service Bulletin J41–05–001, Revision 2, dated March 15, 2002, or BAE Systems (Operations) Limited Service Bulletin J41–05–001, Revision 3, dated January 9, 2004; and BAE Systems (Operations) Limited Service Bulletin J41–32–078, dated April 12, 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 British Aerospace Regional Aircraft American Support, 13850 Mclearen Road, Herndon, Virginia 20171. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 2: The subject of this AD is addressed in British airworthiness directive 007–04–2002.

Effective Date

(i) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14320 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–187–AD; Amendment 39–13688; AD 2004–13–06]

RIN 2120–AA64

Airworthiness Directives; Airbus Model A319 and A320 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Airbus Model A319 and A320 series airplanes, that requires repetitive detailed inspections to detect cracks in the keel beam side panels, and repair if necessary. Accomplishment of the repair ends the repetitive inspections for that repaired area. This action is necessary to detect and correct fatigue cracks on the side panels of the keel beams, which could result in reduced structural integrity of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Tim Dulin, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–2141; fax (425) 227–1149.

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 Airbus Model A319 and A320 series airplanes was published in the **Federal Register** on April 1, 2004 (69 FR 17103). That action proposed to require repetitive detailed inspections to detect cracks in the keel beam side panels, and repair if necessary. Accomplishment of the repair ends the repetitive inspections for that repaired area.

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.

Two commenters request that the notice of proposed rulemaking action (NPRM) be revised to reference the latest service bulletin (*i.e.*, Airbus Service Bulletin A320–53–1060, Revision 01, dated April 2, 2004). The commenters state that Revision 01 only changes the compliance to mandatory.

The FAA agrees. Since issuance of the NPRM, the Direction Générale de l'Aviation Civile (DGAC), which is the airworthiness authority for France, classified Revision 01 of Airbus Service Bulletin A320–53–1060 as mandatory. No additional work is required for airplanes modified by the original issue of the service bulletin (referenced in the NPRM as the appropriate source of service information). Therefore, we have revised the final rule to reference Revision 01 of the service bulletin as the appropriate source of service information for accomplishing the required actions and added a new paragraph to give credit to operators that accomplished the original issue of the service bulletin before the effective date of this AD.

Conclusion

After careful review of the available data, including the comment noted above, we have determined that air safety and the public interest require the adoption of the rule with the changes described previously. We have determined that these changes will neither increase the economic burden on any operator nor increase the scope of the AD.

Cost Impact

We estimates that 400 Model A319 and A320 series airplanes of U.S. registry will be affected by this AD, that it will take approximately 13 work hours per airplane to accomplish the required inspection, 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 $338,000, or $845 per airplane, per inspection cycle.

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:

2004–13–06 Airbus: Amendment 39–13688. Docket 2003–NM–187–AD.

Applicability: Model A319 and A320 series airplanes, certificated in any category; except those airplanes on which Airbus Modification 30355 has been incorporated in production.

Compliance: Required as indicated, unless accomplished previously.

To detect and correct fatigue cracks on the side panels of the keel beams, which could result in reduced structural integrity of the airplane, accomplish the following:

Service Bulletin

(a) The term "service bulletin," as used in this AD, means the Accomplishment Instructions of Airbus Service Bulletin A320–53–1060, Revision 01, dated April 2, 2004.

Initial Inspection

(b) Perform a detailed inspection to detect cracks in the keel beam side panels, in accordance with the service bulletin, at the time specified in either paragraph (b)(1) or (b)(2) of this AD, as applicable.

Note 1: For the purposes of this AD, a detailed inspection is defined as: "An intensive visual examination of a specific structural area, system, installation, or assembly to detect damage, failure, or irregularity. Available lighting is normally supplemented with a direct source of good lighting at intensity deemed appropriate by the inspector. Inspection aids such as a mirror, magnifying lenses, etc., may be used. Surface cleaning and elaborate access procedures may be required."

(1) For airplanes that have not been inspected per Maintenance Review Board (MRB) task 53–31–42: Inspect at the later of the times specified in paragraph (b)(1)(i) and (b)(1)(ii) of this AD.

(i) Prior to the accumulation of 24,200 total flight cycles, or 48,400 total flight hours, whichever occurs first.

(ii) Within 3,500 flight cycles after the effective date of this AD.

(2) For airplanes that have been inspected per MRB task 53–31–42: Inspect at the later of the times specified in paragraph (b)(2)(i) and (b)(2)(ii) of this AD.

(i) Within 4,300 flight cycles or 9,600 flight hours after the last inspection per MRB task 53–31–42, whichever occurs first.

(ii) Within 3,500 flight cycles after the effective date of this AD.

Repetitive Inspections

(c) Repeat the detailed inspection required by paragraph (b) of this AD at intervals not to exceed 4,300 flight cycles or 9,600 flight hours, whichever occurs first.

Corrective Actions

(d) If any crack is found in "Area A" during any inspection required by this AD, before further flight, repair the affected area in accordance with the service bulletin. Once a repair has been accomplished to "Area A," the repetitive inspections of "Area A" required by paragraphs (b) and (c) of this AD are no longer required for that side of the keel beam.

(e) If any crack is found in "Area B" during any inspection required by this AD, before further flight, repair the affected structure per a method approved by either the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate; or the Direction Generale De L'Aviation Civile (DGAC) (or its delegated agent).

Credit for Accomplishing Original Issue of Service Bulletin

(f) Actions accomplished before the effective date of this AD per Airbus Service Bulletin A320–53–1060, dated June 19, 2002, are acceptable for compliance with the applicable requirements of this AD.

Alternative Methods of Compliance

(g) In accordance with 14 CFR 39.19, the Manager, International Branch, FAA, is authorized to approve alternative methods of compliance (AMOCs) for this AD.

Incorporation by Reference

(h) Unless otherwise specified in this AD, the actions shall be done in accordance with Airbus Service Bulletin A320–53–1060, Revision 01, dated April 2, 2004. 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 Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 2: The subject of this AD is addressed in French airworthiness directive 2003–146(B), dated April 16, 2003 (a correction was issued May 14, 2003).

Effective Date

(i) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14530 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–104–AD; Amendment 39–13698; AD 2004–13–16]

RIN 2120–AA64

Airworthiness Directives; Empresa Brasileira de Aeronautica S.A. (EMBRAER) Model EMB–135 and –145 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment supersedes an existing airworthiness directive (AD), applicable to all EMBRAER Model EMB–135 and –145 series airplanes, that currently requires repetitive inspections of the engine thrust reverser stow/transit switches, and corrective action, if necessary. This amendment continues to require the existing requirements and identifies the installation of certain new transit switches, which constitutes terminating action for the repetitive inspections. This action also changes the applicability. The actions specified by this AD are intended to prevent erroneous signals in the Engine Indicating and Crew Alerting System (EICAS) caused by internal corrosion of the thrust reverser stow/transit switches, which could result in uncommanded loss of engine power in flight, or unnecessary aborted takeoffs on the ground.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

The incorporation by reference of a certain other publication listed in the regulations was approved previously by the Director of the Federal Register as of September 5, 2001 (66 FR 43766, August 21, 2001).

ADDRESSES: The service information referenced in this AD may be obtained from Empresa Brasileira de Aeronautica S.A. (EMBRAER), P.O. Box 343—CEP 12.225, Sao Jose dos Campos—SP, Brazil. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/*

federal_register/code_of_federal_regulations/ibr_locations.html.

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–1175; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) by superseding AD 2001–17–03, amendment 39–12394 (66 FR 43766, August 21, 2001) which is applicable to all Empresa Brasileira de Aeronautica S.A. (EMBRAER) Model EMB–135 and –145 series airplanes, was published in the **Federal Register** on March 5, 2004 (69 FR 10360). The action proposed to require installation of certain new transit switches, which would constitute terminating action for the repetitive inspections of AD 2001–17–03. That action also proposed to reduce the applicability of AD 2001–17–03.

Editorial Change

Paragraph (e)(2) of the proposed AD text erroneously states a replacement interval in terms of "hours" rather than "flight hours." We have corrected this error in the final rule. This change will neither increase the economic burden on any operator nor increase the scope of the AD.

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

We have determined that air safety and the public interest require the adoption of the rule as proposed, with the editorial change described previously.

Cost Impact

There are approximately 365 airplanes of U.S. registry that will be affected by this AD.

The actions that are currently required by AD 2001–17–03 and retained in this AD, take approximately 1 work hour per airplane to accomplish, at an average labor rate of $65 per work hour. Based on these figures, the cost impact of the previously required actions on U.S. operators is estimated to be $23,725, or $65 per airplane.

The new actions that are required by this AD will take approximately 2 work hours per airplane to accomplish, at an average labor rate of $65 per work hour. Required parts will cost approximately $194 per airplane. Based on these figures, the cost impact of the new requirements of this AD on U.S. operators is estimated to be $118,260, or $324 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 removing amendment 39–12394 (66 FR 43766, August 21, 2001), and by adding a new airworthiness directive (AD), amendment 39–13698, to read as follows:

2004–13–16 Empresa Brasileira de Aeronautica S.A. (EMBRAER): Amendment 39–13698. Docket 2003–NM–104–AD. Supersedes AD 2001–17–03, Amendment 39–12394.

Applicability: Model EMB–135BJ series airplanes, as listed in EMBRAER Service Bulletin 145LEG–78–0006, Revision 01, dated January 31, 2003; and Model EMB–135 and –145 series airplanes, as listed in EMBRAER Service Bulletin 145–78–0035, Revision 02, dated January 31, 2003; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent erroneous signals in the Engine Indicating and Crew Alerting System (EICAS) caused by internal corrosion of the thrust reverser stow/transit switches, which could result in uncommanded loss of engine power in flight, or unnecessary aborted takeoffs on the ground, accomplish the following:

Restatement of the Requirements of AD 2001–17–03

Initial and Repetitive Inspections, and Corrective Action, if Necessary

(a) For Model EMB–135 and –145 series airplanes: Prior to the accumulation of 2,000 total flight hours, or within 400 flight hours after September 5, 2001 (the effective date of AD 2001–17–03, amendment 39–12394), whichever occurs later, perform the inspection required by paragraph (b) of this AD and repeat the inspection at intervals not to exceed 1,200 flight hours.

(b) For Model EMB–135 and –145 series airplanes: Inspect each of the six stow/transit switches on the #1 and #2 engine thrust reversers by conducting a megohmmeter test to measure insulation resistance according to the Accomplishment Instructions of EMBRAER Service Bulletin 145–78–0029, dated February 2, 2001. If insulation resistance measures 100 megohms or less, before further flight, replace the switch with a new switch in accordance with the service bulletin.

Spares

(c) For Model EMB–135 and –145 series airplanes: As of September 5, 2001, no person shall install, on any airplane, a stow/transit switch part number 83–990–137 or 83–990–152 unless it has been inspected in accordance with this AD.

New Actions Required by This AD

Service Bulletin Reference

(d) The term "service bulletin," as used in the remainder of this AD, means the Accomplishment Instructions of the following service bulletins, as applicable:

(1) For Model EMB–135BJ series airplanes: EMBRAER Service Bulletin 145LEG–78–0006, Revision 01, dated January 31, 2003; and

(2) For Model EMB–135 and –145 series airplanes: EMBRAER Service Bulletin 145–78–0035, Revision 02, dated January 31, 2003.

Terminating Action

(e) Install new transit switches having part number 83–990–168, on both engines of the airplane, at the time indicated in paragraph (e)(1) or (e)(2), as applicable, in accordance with the applicable service bulletin. Accomplishment of the new part installation constitutes terminating action for the inspections required by paragraph (a) of this AD.

(1) For airplanes on which the inspection required by paragraph (a) of this AD has been accomplished: Within 1,200 flight hours from the completion of the last inspection required by paragraph (a) of this AD, or within 400 flight hours after the effective date of this AD, whichever occurs later.

(2) For airplanes on which any inspection required by paragraph (a) of this AD has not been accomplished: Prior to the accumulation of 2,000 total flight hours, or within 400 flight hours after the effective date of this AD, whichever occurs later.

Actions Accomplished per Previous Issue of Service Bulletin

(f) Installation of new transit switches having part number 83–990–168 on both engines of the airplane accomplished before the effective date of this AD, in accordance with EMBRAER Service Bulletin 145–78–0035, dated October 4, 2002; EMBRAER Service Bulletin 145–78–0035, Revision 01, dated December 11, 2002; or EMBRAER Service Bulletin 145LEG–78–0006, dated January 13, 2003; as applicable; is considered acceptable for compliance with the terminating action required by paragraph (e) of this AD.

Alternative Methods of Compliance

(g) In accordance with 14 CFR 39.19, the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(h) Unless otherwise specified in this AD, the actions shall be done in accordance with EMBRAER Service Bulletin 145–78–0029, dated February 2, 2001; EMBRAER Service Bulletin 145–78–0035, Revision 02, dated January 31, 2003; and EMBRAER Service Bulletin 145LEG–78–0006, Revision 01, dated January 31, 2003; as applicable. EMBRAER Service Bulletin 145–78–0035, Revision 02, dated January 31, 2003, contains the following effective pages:

Page No.	Revision level shown on page	Date shown on page
1, 2	02	Jan. 31, 2003.
3–13	Original	Oct. 4, 2002.

EMBRAER Service Bulletin 145LEG–78–0006, Revision 01, dated January 31, 2003, contains the following effective pages:

Page No.	Revision level shown on page	Date shown on page
1, 2	01	Jan. 31, 2003.
3–13	Original	Jan. 13, 2003.

(1) The incorporation by reference of EMBRAER Service Bulletin 145–78–0035, Revision 02, dated January 31, 2003; and EMBRAER Service Bulletin 145LEG–78–0006, Revision 01, dated January 31, 2003; is approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51.

(2) The incorporation by reference of EMBRAER Service Bulletin 145–78–0029, dated February 2, 2001, was approved previously by the Director of the Federal Register as of September 5, 2001 (66 FR 43766, August 21, 2001).

(3) Copies may be obtained from Empresa Brasileira de Aeronautica S.A. (EMBRAER), P.O. Box 343—CEP 12.225, Sao Jose dos Campos—SP, Brazil. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 1: The subject of this AD is addressed in Brazilian airworthiness directive 2001–05–03R3, dated April 22, 2003.

Effective Date

(i) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14566 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–52–AD; Amendment 39–13696; AD 2004–13–14]

RIN 2120–AA64

Airworthiness Directives; Airbus Model A300 B2 Series Airplanes; Model A300 B4 Series Airplanes; and Model A300 B4–600, B4–600R, C4 605R Variant F, and F4–600R (Collectively Called A300–600) Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to all Airbus Model A300 B2 series airplanes; Model A300 B4 series airplanes; and Model A300 B4–600, B4–600R, C4 605R Variant F, and F4–600R (collectively called A300–600) series airplanes; that requires inspection of the label of certain slat friction brakes for correct label wording, and corrective actions if necessary. This AD also provides for optional terminating actions for certain repetitive corrective actions. These actions are necessary to find and fix incorrect labels on the housings of the slat friction brakes, which may lead to the use of unapproved oil in the brakes. Use of unapproved oil could affect the efficiency of the brakes and lead to failure of the brakes to maintain proper slat orientation in the event of a rupture of the slat drive shaft, consequent uncommanded retraction of the slat, and reduced controllability of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in the proposed rule may be obtained from Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/*

code_of_federal_regulations/ ibr_locations.html.

FOR FURTHER INFORMATION CONTACT: Dan Rodina, Aerospace Engineer; International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–2125; fax (425) 227–1149.

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 all Airbus Model A300 B2 series airplanes; Model A300 B4 series airplanes; and Model A300 B4–600, B4–600R, C4 605R Variant F, and F4–600R (collectively called A300–600) series airplanes; was published in the **Federal Register** on March 24, 2004 (69 FR 13763). That action proposed to require inspection of the label of certain slat friction brakes for correct label wording, and corrective actions if necessary. That action also provided for optional terminating actions for certain repetitive corrective actions.

Comments

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

Request To Add Preemptive Brake Replacement Option

One commenter, an operator, requests an option be added to allow removal and replacement of friction brakes prior to further flight without performing the oil replacement/sampling requirements. The commenter states that it has already accomplished the specified inspections and replaced any suspect brakes on all its airplanes.

The FAA agrees with the commenter. Paragraph (d)(2) of this AD already provides the option to terminate the repeat torque verification by replacing the brake. We recognize that if the replacement specified in paragraph (d)(2) is performed prior to further flight after the inspection required by paragraph (b) of this AD, it is not necessary to perform the requirements of paragraph (c) of this AD. Therefore, paragraphs (b), (c) and (d) have been rewritten to address this concern.

Conclusion

After careful review of the available data, including the comment noted above, the FAA has determined that air safety and the public interest require the adoption of the rule with the changes described previously. The FAA has determined that these changes will neither increase the economic burden on any operator nor increase the scope of the AD.

Cost Impact

The FAA estimates that 120 airplanes of U.S. registry will be affected by this AD, that it will take approximately 1 work hour per airplane to accomplish the required actions, 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 $7,800, or $65 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:

2004–13–14 Airbus: Amendment 39–13696. Docket 2003–NM–52–AD.

Applicability: All Model A300 B2 series airplanes; Model A300 B4 series airplanes; and Model A300 B4–600, B4–600R, C4 605R Variant F, and F4–600R (collectively called A300–600) series airplanes; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent the possible use of unqualified oil in the slat friction brakes, which could cause failure of the brakes to maintain proper slat orientation in the event of a rupture of the slat drive shaft, consequent uncommanded retraction of the slats, and reduced controllability of the airplane, accomplish the following:

All Operators Telex (AOT) Reference

(a) The term AOT as used in this AD means paragraph 4.3, "Description," of the following, as applicable:

(1) For Model A300 B2 and A300 B4 series airplanes: Airbus AOT 27A0199, Revision 01, dated February 5, 2003.

(2) For Model A300 B4–600, B4–600R, C4–605R Variant F, and F4–600R (collectively called A300–600) series airplanes: Airbus AOT 27A6055, Revision 01, dated February 5, 2003.

Inspection

(b) Within 3 weeks from the effective date of this AD, perform a general visual inspection of the label on the housings of the slat friction brakes for correct wording, in accordance with the applicable AOT. Accomplishment of the requirements of paragraph (d)(2) of this AD prior to further flight after accomplishing paragraph (b) eliminates the requirement for paragraph (c) of this AD.

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."

Corrective Actions

(c) If the wording of the label is found to be incorrect during the inspection required by paragraph (b) of this AD, prior to further flight, remove the label, then perform the actions specified in paragraphs (c)(1), (c)(2), and (c)(3) of this AD in accordance with the applicable AOT, or perform the actions specified in paragraph (d)(2) of this AD.

(1) Within 500 flight hours after removing the incorrect label, apply a correctly worded label to the housing.

(2) Prior to further flight after removing the label, drain the friction brake and refill with Exxon 2120 oil.

(3) Prior to further flight after removing the label, verify the torque of the friction brake.

(i) If the torque is within the limits specified in the applicable AOT, repeat the torque verification thereafter at intervals not to exceed 500 flight hours, until the optional terminating actions specified in paragraph (d) of this AD have been accomplished.

(ii) If the torque is not within the limits specified in the applicable AOT, prior to further flight, replace the friction brake with a new brake in accordance with the applicable AOT. Accomplishment of this replacement terminates the requirement for the repetitive torque verification for that brake.

Optional Terminating Actions

(d) Accomplishment of either paragraph (d)(1) or (d)(2) of this AD terminates the repetitive torque verification required by paragraph (c)(3)(i) of this AD.

(1) Analyze the oil drained from the friction brake.

(i) If the oil is Exxon 2120, no further action is required by this AD.

(ii) If the oil is not Exxon 2120, prior to further flight, replace the friction brake as specified in paragraph (d)(2) of this AD.

(2) Replace the friction brake with a new brake in accordance with the applicable AOT.

Analysis of Brake Oil

(e) Although the referenced AOTs describes procedures for submitting oil drained from the friction brakes to the brake manufacturer for analysis, this AD does not require that the manufacturer be the sole source of such analysis.

Alternative Methods of Compliance

(f) In accordance with 14 CFR 39.19, the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(g) The actions shall be done in accordance with Airbus All Operators Telex 27A0199, Revision 01, dated February 5, 2003; or Airbus All Operators Telex 27A6055, Revision 01, dated February 5, 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 Airbus, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 2: The subject of this AD is addressed in French airworthiness directive 2003–048(B), dated February 5, 2003.

Effective Date

(h) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14567 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–65–AD; Amendment 39–13695; AD 2004–13–13]

RIN 2120–AA64

Airworthiness Directives; Empresa Brasileira de Aeronautica S.A. (EMBRAER) Model EMB–120 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain EMBRAER Model EMB–120 series airplanes, that requires a one-time inspection of the access door ramp of the fueling control panel for damage or deformation, and applicable corrective actions. This action is necessary to prevent inadvertent fuel transfer in flight due to fuel service personnel not repositioning the defuel valve switch control to the closed position after utilization on the ground, which could cause in-flight fuel starvation. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Empresa Brasileira de Aeronautica S.A. (EMBRAER), P.O. Box 343—CEP 12.225, Sao Jose dos Campos—SP, Brazil. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741-6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Dan Rodina, Aerospace Engineer; International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–2125; fax (425) 227–1149.

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 EMBRAER Model EMB–120 series airplanes was published in the **Federal Register** on April 6, 2004 (69 FR 17989). That action required a one-time inspection of the access door ramp of the fueling control panel for damage or deformation, and applicable corrective actions.

Comments

Interested persons have been afforded an opportunity to participate in the making of this amendment. No comments have been submitted on the proposed AD or on the determination of the cost to the public.

Conclusion

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

Cost Impact

The FAA estimates that 220 airplanes of U.S. registry will be affected by this AD, that it will take approximately 4 work hours per airplane to accomplish each required action, and that the average labor rate is $65 per work hour. Required parts will cost approximately $200 per airplane. Based on these figures, the cost impact of the AD on U.S. operators is estimated to be $101,200, or $460 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:

2004–13–13 Empresa Brasileira de Aeronautica S.A. (EMBRAER): Amendment 39–13695. Docket 2003–NM–65–AD.

Applicability: Model EMB–120 series airplanes, serial numbers 120003, 120004, and 120006 through 120358 inclusive; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent inadvertent fuel transfer in flight due to fuel service personnel not repositioning the defuel valve switch control to the closed position after utilization on the ground, which could cause in-flight fuel starvation, accomplish the following:

Inspection of Existing Ramp and Corrective Actions

(a) For airplanes that have a ramp on the access door of the fueling control panel: Within 1,200 flight hours or 8 months after the effective date of this AD, whichever occurs first, perform a general visual inspection of the access door ramp for damage or deformation; and do all applicable corrective actions by accomplishing all the actions in accordance with paragraph 2.2.3 of the Accomplishment Instructions of EMBRAER Service Bulletin 120–57–0038, dated June 26, 2002. Do the actions per the service bulletin. Accomplish any applicable corrective actions before further flight.

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."

Modification

(b) For airplanes that do not have a ramp on the access door of the fueling control panel: Within 1,200 flight hours or 8 months after the effective date of this AD, whichever occurs first, modify the access door by accomplishing all the actions in paragraph 2.1.3 of the Accomplishment Instructions of EMBRAER Service Bulletin 120–57–0038, dated June 26, 2002. Do the actions per the service bulletin. Accomplish any applicable corrective actions before further flight.

Alternative Methods of Compliance

(c) In accordance with 14 CFR 39.19, the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(d) The actions shall be done in accordance with EMBRAER Service Bulletin 120–57–0038, dated June 26, 2002. 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 Empresa Brasileira de Aeronautica S.A. (EMBRAER), P.O. Box 343—CEP 12.225, Sao Jose dos Campos—SP, Brazil. Copies may be inspected at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 2: The subject of this AD is addressed in Brazilian airworthiness directive 2002–12–02, effective January 6, 2003.

Effective Date

(e) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14569 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–126–AD; Amendment 39–13697; AD 2004–13–15]

RIN 2120–AA64

Airworthiness Directives; Boeing Model 747–400 and –400D Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Boeing Model 747–400 and –400D series airplanes, that requires an inspection to detect missing fasteners in the section 42 skin and internal doubler at the cutout for the ground exhaust valve of the electrical equipment; modification and rework of the doubler; repetitive inspections of the skin for cracks; and corrective actions if necessary; as applicable. This action is necessary to detect and correct fatigue cracks in the section 42 skin at the cutout for the ground exhaust valve of the electrical equipment, which could result in rapid decompression of the airplane. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of August 3, 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Candice Gerretsen, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 917–6428; 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 747–400 and –400D series airplanes was published in the **Federal Register** on April 1, 2004 (69 FR 17073). That action proposed to require an inspection to detect missing fasteners in the section 42 skin and internal doubler at the cutout for the ground exhaust valve of the electrical equipment; modification and rework of the doubler; repetitive inspections of the skin for cracks; and corrective actions if necessary; as applicable.

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 142 airplanes of the affected design in the worldwide fleet. The FAA estimates that 22 airplanes of U.S. registry will be affected by this AD.

For Group 1 airplanes listed in Boeing Alert Service Bulletin 747–53A2340, it will take approximately 1 work hour per airplane to accomplish the required inspection (part 1), at an average labor rate of $65 per work hour. Based on these figures, the cost impact of this inspection required by this AD on U.S. operators is estimated to be $65 per airplane.

For Groups 1 and 2 airplanes listed in Boeing Alert Service Bulletin 747–53A2340, it will take approximately 40 work hours per airplane to accomplish the required modification and rework (part 2), at an average labor rate of $65 per work hour. Based on these figures, the cost impact of this modification and rework required by this AD on U.S. operators is estimated to be $2,600 per airplane.

For Groups 1 through 4 airplanes listed in Boeing Alert Service Bulletin 747–53A2340, it will take approximately 1 work hours per airplane to accomplish the required inspection (part 3), at an average labor rate of $65 per work hour. Based on these figures, the cost impact of this inspection required by this AD on U.S. operators is estimated to be $65 per airplane, per inspection cycle.

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:

2004–13–15 Boeing: Amendment 39–13697. Docket 2003–NM–126–AD.

Applicability: Model 747–400 and 400D series airplanes, as listed in paragraph 1.A., "Effectivity," of Boeing Alert Service Bulletin 747–53A2340, Revision 2, dated April 24, 2003; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To detect and correct fatigue cracks in the section 42 skin at the cutout for the ground exhaust valve of the electrical equipment, which could result in rapid decompression of the airplane, accomplish the following:

Part 1—Fastener Inspection and Corrective Actions if Necessary

(a) For Group 1 airplanes listed in Boeing Alert Service Bulletin 747–53A2340, Revision 2, dated April 24, 2003: Within 250 flight cycles or 4 months after the effective date of this AD, whichever occurs later, do a general visual inspection to detect missing fasteners in the section 42 skin and internal doubler at the cutout for the ground exhaust valve of the electrical equipment, per part 1 of the Accomplishment Instructions of the service bulletin.

(1) If all fasteners are installed, do the actions specified in paragraph (b) of this AD at the indicated time.

(2) If any fastener is missing, before further flight, accomplish all applicable corrective actions (*i.e.*, performing an open hole high frequency (HFEC) inspection for cracks and any applicable repair, oversizing and drilling of holes, and installation of fasteners), in accordance with part 1 of the Accomplishment Instructions of the service bulletin, except as required by paragraph (f) of this AD.

Part 2—Modification and Rework

(b) For Group 1 and Group 2 airplanes listed in Boeing Alert Service Bulletin 747–53A2340, Revision 2, dated April 24, 2003: Before the accumulation of 6,000 total flight cycles, or within 1,500 flight cycles or 24 months after the effective date of this AD, whichever occurs later, modify and rework the internal doubler (*i.e.*, performing an open hole HFEC inspection for cracks and any applicable repair, oversizing and drilling of holes, and installation of fasteners) by accomplishing all actions specified in part 2 of the Accomplishment Instructions of the service bulletin. Do the actions per the service bulletin, except as required by paragraph (f) of this AD. Any applicable repair must be accomplished before further flight.

Part 3—Repetitive Inspections and Repair if Necessary

(c) At the applicable time specified in paragraph (c)(1) or (c)(2) of this AD, do an external HFEC inspection of the skin for cracks per part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2340, Revision 2, dated April 24, 2003.

(1) For Group 1 and Group 2 airplanes listed in the service bulletin: Within 10,000 flight cycles after accomplishing the actions required by paragraph (b) of this AD, or within 1,500 flight cycles or 24 months after the effective date of this AD, whichever occurs later.

(2) For Group 3 and Group 4 airplanes listed in the service bulletin: Before the accumulation of 15,000 total flight cycles, or within 1,500 flight cycles or 24 months after the effective date of this AD, whichever occurs later.

(d) If no crack is detected during the external HFEC inspection required by paragraph (c) of this AD, repeat the external HFEC inspection thereafter at intervals not to exceed 5,000 flight cycles.

(e) If any crack is detected during the external HFEC inspection required by paragraph (c) of this AD, before further flight, repair per part 3 of the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2340, Revision 2, dated April 24, 2003, except as required by paragraph (f) of this AD. Repeat the external HFEC inspection in the unrepaired areas thereafter at intervals not to exceed 5,000 flight cycles.

Exception to Service Bulletin Actions

(f) If any discrepancy is found during any inspection required by this AD, and the bulletin specifies to contact Boeing for an alternate repair: Before further flight, repair per a method approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA; or per data meeting the type certification basis of the airplane approved by a Boeing Company Designated Engineering Representative who has been authorized by the Manager, Seattle ACO, to make such findings. For a repair method to be approved, the approval must specifically reference this AD.

Credit for Previous Revisions of Service Bulletins

(g) Actions accomplished before the effective date of this AD per Boeing Alert Service Bulletin 747–53A2340, original issue, dated August 1, 1991; or Revision 1, dated October 31, 1991, are acceptable for compliance with the requirements of this AD.

Alternative Methods of Compliance

(h)(1) In accordance with 14 CFR 39.19, the Manager, Seattle ACO, FAA, is authorized to approve alternative methods of compliance (AMOCs) for this AD.

(2) An AMOC that provides an acceptable level of safety may be used for any inspection or repair required by this AD, if it is approved by a Boeing Company Designated Engineering Representative who has been authorized by the Manager, Seattle ACO, to make such findings. For an inspection or repair method to be approved, the approval must specifically reference this AD.

Incorporation by Reference

(i) Unless otherwise specified in this AD, the actions shall be done in accordance with Boeing Alert Service Bulletin 747–53A2340, Revision 2, dated April 24, 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Effective Date

(j) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 17, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14568 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2003–NM–200–AD; Amendment 39–13703; AD 2004–13–21]

RIN 2120–AA64

Airworthiness Directives; Short Brothers Model SD3–60 SHERPA Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to all Short Brothers Model SD3–60 SHERPA series airplanes, that requires repetitive inspections and torque tests for discrepancies of certain bolts and rivets; and related investigative and corrective actions. This action is necessary to detect and correct loose bolts that attach the vertical stabilizer to the horizontal stabilizer, and pulled or loose rivets in the upper shear angles, which could result in reduced structural integrity of the vertical stabilizer. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of a certain publication listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Short Brothers, Airworthiness & Engineering Quality, P.O. Box 241, Airport Road, Belfast BT3 9DZ, Northern Ireland. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Todd Thompson, Aerospace Engineer, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–1175; fax (425) 227–1149.

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 all Short Brothers Model SD3–60 SHERPA series airplanes was published in the **Federal Register** on March 25, 2004 (69 FR 15266). That action proposed to require repetitive inspections and torque tests for discrepancies of certain bolts and rivets; and related investigative and corrective actions.

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

The FAA estimates that 27 airplanes of U.S. registry will be affected by this AD, that it will take approximately 5 work hours per airplane to accomplish the required inspections and torque tests, 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 $8,775, or $325 per airplane, per inspection/test cycle.

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:

2004–13–21 Short Brothers PLC: Amendment 39–13703. Docket 2003–NM–200–AD.

Applicability: All Short Brothers Model SD3–60 SHERPA series airplanes, certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To detect and correct loose bolts that attach the vertical stabilizer to the horizontal stabilizer, and pulled or loose rivets in the upper shear angles, which could result in reduced structural integrity of the vertical stabilizer, accomplish the following:

Repetitive Inspections and Torque Tests and Related Investigative Action

(a) Prior to the accumulation of 1,500 total flight hours, or within 2 months after the effective date of this AD, whichever occurs later: Perform a detailed inspection, including a torque test, to detect discrepancies in the bolts or bolt holes that attach the vertical stabilizer to the horizontal stabilizer; and to detect loose or pulled rivets in the upper shear angles. Repeat the detailed inspection and torque test at intervals not to exceed 1,500 flight hours. If any discrepancy is found in the bolts or bolt holes, do the related investigative action before further flight. Accomplish all actions in accordance with the Accomplishment Instructions of Short Brothers Service Bulletin SD3–60 Sherpa–55–1, dated June 6, 2003.

Note 1: For the purposes of this AD, a detailed inspection is defined as: "An intensive visual examination of a specific structural area, system, installation, or assembly to detect damage, failure, or irregularity. Available lighting is normally supplemented with a direct source of good lighting at intensity deemed appropriate by the inspector. Inspection aids such as mirror, magnifying lenses, *etc.*, may be used. Surface cleaning and elaborate access procedures may be required."

Related Corrective Actions

(b) If any discrepancy is found during any inspection or torque test required by paragraph (a) of this AD: Before further flight, repair in accordance with the Accomplishment Instructions of Short Brothers Service Bulletin SD3–60 Sherpa–55–1, dated June 6, 2003. Where the service bulletin specifies to contact the manufacturer for disposition of certain repair conditions: Before further flight, repair per a method approved by either the Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate; or the Civil Aviation Authority or its delegated agent.

No Reporting Requirement

(c) Although the service bulletin referenced in this AD specifies to submit certain information to the manufacturer, this AD does not include such a requirement.

Alternative Methods of Compliance

(d) In accordance with 14 CFR 39.19, the Manager, International Branch, is authorized to approve alternative methods of compliance for this AD.

Incorporation by Reference

(e) Unless otherwise specified in this AD, the actions shall be done in accordance with Short Brothers Service Bulletin SD3–60 Sherpa–55–1, dated June 6, 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 Short Brothers, Airworthiness & Engineering Quality, P.O. Box 241, Airport Road, Belfast BT3 9DZ, Northern Ireland. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Note 2: The subject of this AD is addressed in British airworthiness directive 001–06–2003.

Effective Date

(f) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 16, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14572 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 2002–NM–254–AD; Amendment 39–13702; AD 2004–13–20]

RIN 2120–AA64

Airworthiness Directives; Aircraft Equipped With Garmin AT, Apollo GX Series Global Positioning System (GPS) Navigation Units With Software Versions 3.0 through 3.4 Inclusive

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to aircraft equipped with Garmin AT, Apollo GX series GPS navigation units with software versions 3.0 through 3.4 inclusive, that requires modification and testing of the software for Apollo GX50/55/60/65 TSO–C129a GPS navigation units; and

reidentification of the part. This action is necessary to prevent the GPS navigation unit, under certain conditions, from providing erroneous cross-deviation information, which could result in the aircraft deviating from its intended course for a brief period of time. Erroneous information may also place an excessive workload on the flightcrew while they monitor other available navigation data to avoid deviating off course. This action is intended to address the identified unsafe condition.

DATES: Effective August 3, 2004.

The incorporation by reference of a certain publication listed in the regulations is approved by the Director of the Federal Register as of August 3, 2004.

ADDRESSES: The service information referenced in this AD may be obtained from Garmin AT, 2345 Turner Road Southeast, Salem, Oregon 97302. 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 National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

FOR FURTHER INFORMATION CONTACT: Walter Cameron, Aerospace Engineer, Systems and Equipment Branch, ANM–130S, FAA, Seattle Aircraft Certification Office, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 917–6460; 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 aircraft equipped with Garmin AT, Apollo GX series GPS navigation units with software versions 3.0 through 3.4 inclusive was published in the **Federal Register** on April 1, 2004 (69 FR 17076). That action proposed to require modification and testing of the software for Apollo GX50/55/60/65 TSO–C129a GPS navigation units; and reidentification of the part.

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 do not know how many aircraft equipped with Apollo GX series GPS navigation units (software versions 3.0 through 3.4 inclusive) of the affected design are on the U.S. Register. However, we do know that the GPS navigation units might be installed on 1,176 aircraft worldwide. It will take approximately 1 work hour per aircraft to accomplish the required modification, at an average labor rate of $65 per work hour. The parts manufacturer will provide the required parts at no cost to the operator. Based on these figures, the cost impact of the AD on U.S. operators is estimated to be $65 per aircraft.

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. Manufacturer warranty remedies may be available for labor costs associated with this AD. 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:

2004–13–20 Garmin AT (formerly UPS Aviation Technologies, Inc.): Amendment 39–13702. Docket 2002–NM–254–AD.

Applicability: Aircraft equipped with Garmin AT, Apollo GX50/55/60/65 TSO–C129a global positioning system (GPS) navigation units with software versions 3.0 through 3.4 inclusive; as listed in UPS Aviation Technologies Service Bulletin 561–4002–001, dated April 19, 2002; certificated in any category.

Compliance: Required as indicated, unless accomplished previously.

To prevent the GPS navigation unit, under certain conditions, from providing erroneous cross-deviation information, which could result in the aircraft deviating from its intended course for a brief period of time; and to also prevent erroneous information from placing an excessive workload on the flightcrew while they monitor other available navigation data to avoid deviating off course; accomplish the following:

Software Modification, Testing, and Reidentification

(a) Within 6 months after the effective date of this AD, do the actions specified in paragraphs (a)(1) and (a)(2) of this AD, according to the Accomplishment Instructions of UPS Aviation Technologies Service Bulletin 561–4002–001, dated April 19, 2002.

(1) Modify and test the software for the Apollo GX50/55/60/65 TSO–C129a GPS navigation unit by accomplishing all of the actions specified in paragraphs 3.B. and 3.C. of the service bulletin.

(2) Reidentify the modified Apollo GX50/55/60/65 TSO–C129a GPS navigation unit, according to paragraph 3.D. of the service bulletin.

Alternative Methods of Compliance

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

Incorporation by Reference

(c) The actions shall be done in accordance with UPS Aviation Technologies Service Bulletin 561–4002–001, dated April 19, 2002. 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 Garmin AT, 2345 Turner Road Southeast, Salem, Oregon 97302. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call (202) 741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

Effective Date

(d) This amendment becomes effective on August 3, 2004.

Issued in Renton, Washington, on June 17, 2004.

Ali Bahrami,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 04–14573 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 95

[Docket No. 30417; Amdt. No. 449]

IFR Altitudes; Miscellaneous Amendments

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts miscellaneous amendments to the required IFR (instrument flight rules) altitudes and changeover points for certain Federal airways, jet routes, or direct routes for which a minimum or maximum en route authorized IFR altitude is prescribed. This regulatory action is needed because of changes occurring in the National Airspace System. These changes are designed to provide for the safe and efficient use of the navigable airspace under instrument conditions in the affected areas.

DATES: *Effective Date:* 0901 UTC, August 5, 2004.

FOR FURTHER INFORMATION CONTACT: Donald P. Pate, Flight Procedure Standards Branch (AMCAFS–420), Flight Technologies and Programs Division, Flight Standards Service, Federal Aviation Administration, Mike Monroney Aeronautical Center, 6500 South MacArthur Blvd., Oklahoma City, OK 73169. (Mail Address: PO Box 25082, Oklahoma City, OK 73125.) telephone: (405) 954–4164.

SUPPLEMENTARY INFORMATION: This amendment to part 95 of the Federal Aviation Regulations (14 CFR part 95) amends, suspends, or revokes IFR altitudes governing the operation of all aircraft in flight over a specified route or any portion of that route, as well as the changeover points (COPs) for Federal airways, jet routes, or direct routes as prescribed in part 95.

The Rule

The specified IFR altitudes, when used in conjunction with the prescribed changeover points for those routes, ensure navigation aid coverage that is adequate for safe flight operations and free of frequency interference. The reasons and circumstances that create the need for this amendment involve matters of flight safety and operational efficiency in the National Airspace System, are related to published aeronautical charts that are essential to the user, and provide for the safe and efficient use of the navigable airspace. In addition, those various reasons or circumstances require making this amendment effective before the next scheduled charting and publication date of the flight information to assure its timely availability to the user. The effective date of this amendment reflects those considerations. In view of the close and immediate relationship between these regulatory changes and safety in air commerce, I find that notice and public procedure before adopting this amendment are impracticable and contrary to the public interest and that good cause exists for making the amendment effective in less than 30 days.

Conclusion

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. *It, therefore*—(1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. For the same reason, the FAA certifies that this amendment will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 95

Airspace, Navigation (air).

Issued in Washington, DC on June 22, 2004.

James J. Ballough,

Director, Flight Standards Service.

Adoption of the Amendment

■ Accordingly, pursuant to the authority delegated to me by the Administrator, part 95 of the Federal Aviation Regulations (14 CFR part 95) is amended as follows effective at 0901 UTC.

■ 1. The authority citation for part 95 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40103, 40106, 40113, 40114, 40120, 44502, 44514, 44719, 44721.

■ 2. Part 95 is amended to read as follows:

REVISIONS TO IFR ALTITUDES AND CHANGEOVER POINTS AMENDMENT 449

[Effective Date, August 05, 2004; Final, 06/16/2004]

From	To	MEA
§95.6001 VICTOR ROUTES–U.S.		
§95.6010 VOR Federal Airway 10 Is Amended To Read in Part		
VOLAN, PA FIX	*Eared, PA FIX	**4,000
*4,000—MRA		
**3,100—MOCA		
EARED, PA FIX	Talls, PA FIX	*4,000

REVISIONS TO IFR ALTITUDES AND CHANGEOVER POINTS AMENDMENT 449—Continued
[Effective Date, August 05, 2004; Final, 06/16/2004]

From	To	MEA
*3,100—MOCA		
§ 95.6013 VOR Federal Airway 13 Is Amended To Read in Part		
LUFKIN, TX VORTAC	Carth, TX FIX	*3,800
*2,400–MOCA		
CARTH, TX FIX	Belcher, LA VORTAC	3,100
§ 95.6038 VOR Federal Airway 38 Is Amended To Read in Part		
HARCUM, VA VORTAC	Cape Charles, VA VORTAC	2,000
§ 95.6068 VOR Federal Airway 68 Is Amended To Read in Part		
MIDLAND, TX VORTAC	Jokes, TX FIX	4,500
JOKES, TX FIX	Steep, TX FIX	*5,000
*4,200—MOCA		
§ 95.6137 VOR Federal Airway 137 Is Amended To Read in Part		
IMPERIAL, CA VORTAC	*Brawl, CA FIX	**3,700
*4,500—MRA		
**2,300—MOCA		
BRAWL, CA FIX	Henhom, CA FIX	3,700
HENOM, CA FIX	Thermal, CA VORTAC	3,900
§ 95.6139 VOR Federal Airway 139 Is Amended To Read in Part		
EWOOD, VA FIX	Snow Hill, MD VORTAC	6,000
§ 95.6210 VOR Federal Airway 210 Is Amended To Read in Part		
VOLAN, PA FIX	*Eared, PA FIX	**4,000
*4,000—MRA		
**3,100—MOCA		
EARED, PA FIX	Talls, PA FIX	*4,000
*3,100—MOCA		
§ 95.6297 VOR Federal Airway 297 Is Amended To Read in Part		
TALLS, PA FIX	*Eared, PA FIX	**4,000
*4,000—MRA		
**3,100—MOCA		
EARED, PA FIX	Volan, PA FIX	*4,000
*3,100—MOCA		
§ 95.6328 VOR Federal Airway 328 Is Amended By Adding		
JACKSON, WY VOR/DME	Big Piney, WY VOR/DME	13,500
§ 95.6330 VOR Federal Airway 330 Is Amended To Read in Part		
OSITY, ID FIX	*Jackson, WY VOR/DME	14,000
*13,200—MCA JACKSON VOR/DME, W BND		
§ 95.6465 VOR Federal Airway 465 Is Amended To Read in Part		
LUNDI, ID FIX	Jackson, WY VOR/DME	#*15,000
*13,100—MOCA		
#MEA IS ESTABLISHED WITH A GAP IN NAVIGATIONAL SIGNAL COVERAGE.		
§ 95.6520 VOR Federal Airway 520 Is Amended To Read in Part		
DUBOIS, ID VORTAC	*Jackson, WY VOR/DME	15,000
*14,600—MCA JACKSON VOR/DME, W BND		

From	To	Changeover points	
		Distance	From
§95.8003 VOR FEDERAL AIRWAY CHANGEOVER POINTS Airway segment V–328 Is Amended To Add Changeover Point			
JACKSON, WY VOR/DME	Big Piney VOR/DME	20	Jackson
V–330Is Amended To Add Changeover Point			
IDAHO FALLS, ID VOR/DME	Jackson, WY VOR/DME	48	Idaho Falls
V–465Is Amended To Add Changeover Point			
MALAD CITY, ID VOR/DME	Jackson, WY VOR/DME	63	Malad CITY
V–520Is Amended To Add Changeover Point			
DUBOIS, ID VORTAC	Jackson, WY VOR/DME	60	Dubois

[FR Doc. 04–14629 Filed 6–28–04; 8:45 am]
BILLING CODE 4910–13–P

DEPARTMENT OF THE TREASURY

Alcohol and Tobacco Tax and Trade Bureau

27 CFR Part 9

[T.D. TTB–13; Notice No. 20]

RIN 1513–AA69

Establishment of Salado Creek Viticultural Area (2003R–025P)

AGENCY: Alcohol and Tobacco Tax and Trade Bureau (TTB), Treasury.

ACTION: Final rule; Treasury decision.

SUMMARY: This Treasury decision establishes the Salado Creek viticultural area in western Stanislaus County, California. We designate viticultural areas to allow vintners to better describe the origin of their wines and to allow consumers to better identify wines they may purchase.

EFFECTIVE DATE: August 30, 2004.

FOR FURTHER INFORMATION CONTACT: N. A. Sutton, Program Manager, Regulations and Procedures Division, Alcohol and Tobacco Tax and Trade Bureau, 6660 Delmonico Dr., #D422, Colorado Springs, CO 80919; telephone 415–271–1254.

SUPPLEMENTARY INFORMATION:

Background on Viticultural Areas

TTB Authority

The Federal Alcohol Administration Act (FAA Act) at 27 U.S.C. 205(e) requires that alcohol beverage labels provide the consumer with adequate information regarding a product's identity, while prohibiting the use of misleading information on such labels. The FAA Act also authorizes the Secretary of the Treasury to issue regulations to carry out the Act's provisions. The Alcohol and Tobacco Tax and Trade Bureau (TTB) administers these regulations.

Regulations in 27 CFR part 4, Labeling and Advertising of Wine, allow the establishment of definitive viticultural areas and the use of their names as appellations of origin on wine labels and in wine advertisements. Title 27 CFR part 9, American Viticultural Areas, contains the list of approved viticultural areas.

Definition

Title 27 CFR 4.25(e)(1) defines an American viticultural area as a delimited grape-growing region distinguishable by geographic features whose boundary has been delineated in subpart C of part 9. The establishment of viticultural areas allows the identification of regions where a given quality, reputation, or other characteristics of the wine is essentially attributable to its geographic origin. We believe that the establishment of viticultural areas allows wineries to describe more accurately the origin of their wines to consumers and helps consumers identify the wines they purchase. Establishment of a viticultural area is neither an approval nor endorsement by TTB of the wine produced there.

Requirements

Section 4.25(e)(2) outlines the procedure for proposing an American viticultural area. Anyone interested may petition TTB to establish a grape-growing region as a viticultural area. The petition must include—

- Evidence that the proposed viticultural area is locally and/or nationally known by the name specified in the petition;
- Historical or current evidence that the boundaries of the proposed viticultural area are as specified in the petition;
- Evidence relating to the geographical features, such as climate, soils, elevation, physical features, etc., that distinguish the proposed viticultural area from surrounding areas;
- A description of the proposed viticultural area's specific boundaries, based on features found on maps approved by the United States Geological Survey (USGS); and
- A copy of the appropriate USGS-approved map(s) with the boundaries prominently marked.

A petition requesting the modification of an established viticultural area must include information, evidence, and maps appropriate to support the requested change(s).

Impact on Current Wine Labels

Under our part 4 regulations, State, county, and viticultural area names have viticultural significance. Part 4 also prohibits the use of a brand name or other label reference with viticultural significance on a wine unless the wine meets the appellation of origin requirements for the named geographic area.

With the establishment of this viticultural area, wine bottlers using "Salado Creek" in a brand name, including trademarks, or in another label reference, must ensure that the product is eligible to use the viticultural area's name as an appellation of origin. For a wine to be eligible, at least 85 percent of the grapes in the wine must have been grown within the viticultural area, and the wine must meet the other requirements of 27 CFR 4.25(e)(3).

If the wine is not eligible for the appellation, the bottler must change the brand name or other label reference and obtain approval of a new label. Different rules apply if a wine in this category bears a brand name that was used as a brand name on a label approved prior to

July 7, 1986. *See* 27 CFR 4.39(i) for details.

Salado Creek Petition

In 2002, Stan Grant of Progressive Viticulture filed a petition on behalf of Fred Vogel of the Sunflower Ranch Company in Patterson, California, proposing to establish the "Salado Creek" viticultural area in western Stanislaus County, California. The 2,940-acre viticultural area, which had 44 acres of vineyards in 2002, is located about 75 miles east-southeast of San Francisco and 18 miles southwest of Modesto in a rural area of central, interior California. The Salado Creek area is located along Interstate 5 on the western edge of the San Joaquin Valley, just southwest of the town of Patterson. The Diablo Mountains rise to the west of the viticultural area and shield it from the Pacific Ocean's marine influence. Salado Creek flows from the mountains through the viticultural area, while Little Salado Creek touches its southern tip.

Name Evidence

Spanish explorer Gabriel Moraga named Salado Creek. Moraga, a Spanish army officer, explored the San Joaquin Valley during his 1806–1811 expeditions to the San Joaquin Valley and named many of its geographic features. The names "Salado" and "Salado Creek" continue to be used in modern times and are attached to a variety of features and places, both natural and man-made.

As shown on the two official United States Geological Survey (USGS) maps that cover the viticultural area, the Patterson and Crows Landing quadrangles, Salado Creek is an intermittent stream that flows east from the higher elevations of the Diablo Mountains. After passing under Interstate 5, Salado Creek turns and flows north through the viticultural area and continues west and north of the town of Patterson.

The USGS Patterson map shows Little Salado Creek running east from the Diablo Mountains to the viticultural area's southern tip, where Interstate 5 and the California Aqueduct interrupt its natural channel. On the USGS Crows Landing map, the creek is shown to resume southeast of the area where it runs northeast from the Delta-Mendota Canal. The Salado Sub-Station, south of Salado Creek and beside the California Aqueduct, is within the viticultural area.

The Salado Creek Ranch, known for its walnuts, is within the established boundaries. Salado Avenue in Patterson is a major street that passes the town's post office, its branch library, a new school, and the city council's chambers. The local irrigation district was previously known as the Salado Irrigation District.

Salado Creek is best known to local residents for its floods. "Salado Creek History," an article published in "The Gateway: A Patterson Township History Society Bulletin" in December 1996, discusses the creek's significant floods. As noted in the article, the March 4, 1938, edition of the local Patterson Irrigator newspaper states that Salado Creek spilled over its banks and onto State Highway 33 on Patterson's east side. The article adds that a flood in November of 1938 spilled into a local nursery.

Boundary Evidence

The waters from Salado Creek and Little Salado Creek have deposited large quantities of sediment on the flood plain and formed an alluvial fan. Further, these sediments are the parent material for the Ensalado soil series, which are unique to western Stanislaus County. The Salado Creek viticultural area boundaries, which are on this alluvial fan, generally coincide with the extent of the Ensalado soil series.

Distinguishing Features

Topography

The Salado Creek viticultural area lies on the western side of the San Joaquin Valley at the foot of the Diablo Mountains, which are part of California's Coast Range. The viticultural area is between 125 and 340 feet above sea level and generally flat with a gentle downward slope to the northeast, toward the San Joaquin River. A number of man-made canals, ditches, and drains cross the area's boundary. The California Aqueduct and the Delta-Mendota Canal, for example, flow from the northwest to the southeast across the Salado Creek viticultural area.

Salado Creek is the major natural watercourse for the Salado Creek viticultural area. As an intermittent stream, it begins in the Diablo Mountain Range to the area's west and runs east in its natural channel from the mountains to the California Aqueduct. After crossing the Aqueduct at the foot of the Diablos, the creek flows north and then northeasterly across the gently sloping floor of the San Joaquin Valley. After crossing the Delta-Mendota Canal in a flume, it enters a man-made channel that carries it north from the viticultural area and then east around the heart of Patterson. Finally, Salado Creek enters large drainpipes at State Route 33, which take its water to the San Joaquin River.

Another intermittent stream, Little Salado Creek, starts in the Diablo range south of Salado Creek. It meanders east in its natural channel to the southern tip of the viticultural area at Interstate 5 and Fink Road. The creek then enters a series of man-made drains and channels as it flows northeast across the valley floor outside of the viticultural area, south of Patterson.

The Salado Creek viticultural area covers the upper portion and back slope of the alluvial fan created by Salado and Little Salado Creeks. The two creeks created the fan where they left the steep slopes of the Diablo Mountains and their flow velocity diminished as they entered the much gentler slopes of the San Joaquin Valley. This drop in velocity allowed the coarser, heavier sediments to settle out and formed the creeks' alluvial fan at the foot of the Diablos. The two streams carried finer, lighter sediments further downstream to the flood plain of the San Joaquin River. The coarser, heavier sediments of the alluvial fan became the parent material for the Ensalado soils found within the viticultural area boundaries.

Soils

The Ensalado series soils, formerly known as the Salado series, are unique to west Stanislaus County, California, according to a 2001 publication by soil scientist, vineyard consultant, and Salado Creek petition author Stan Grant. He further notes that this soil series occurs only along three streams in the area, Salado, Orestimba, and Del Puerto Creeks, and accounts for only 0.17 percent of the soils covering western Stanislaus County. Mr. Grant notes in the petition that because of their lower flow velocity, Salado Creek and Little Salado Creek dropped large quantities of sediment immediately after leaving the Diablo Mountains. This produced the large alluvial fan upon which the Salado Creek viticultural area sits. The Orestimba and Del Puerto Creeks, with their higher flow rates, took their sediments further to the east, producing smaller alluvial fans at the foot of the mountains.

The Ensalado soils are very deep, with a root depth of 60 inches or more. They are well drained, with parent material from sandstone and shale, and have little organic matter. They have limited layer development due to the dry, warm climate, and are calcareous. Classified as coarse-loamy, these soils generally consist of a thin layer of fine sandy loam over deep loam subsoil. Other soils on the alluvial fan, older than the Ensalado soils, lie beyond the courses of Salado and Little Salado Creeks.

Climate

The Salado Creek viticultural area lies on the west side of the San Joaquin Valley at the foot of the Diablo Mountains. This range shields the area from the maritime influences of the Pacific Ocean. Also, the Salado Creek area is in a "thermal belt," which covers the alluvial fans along the western rim of the valley in Stanislaus County. Consistent breezes from the north, which cool the area in the summer, characterize this thermal belt. In the winter it has less fog and warmer temperatures than the valley's lower elevations along the San Joaquin River.

The petition included a recent comparison of weather information gathered from stations north, within, and south of the Salado Creek viticultural area. It has warmer minimum temperatures and cooler maximum temperatures, for a milder climate, than the surrounding areas. Minimum temperatures are higher in May, June, and August through October. Maximum temperatures are cooler August through December. These periods of comparatively mild temperatures correspond to the ripening season for wine grapes.

Solar radiation statistics for 2001 indicate less solar influence between August and October in the viticultural area, creating a slower ripening period for the grapes. The area's low humidity, high average wind speeds, and high average solar radiation create a high rate of moisture evaporation from the plants and soil. This slow ripening, and the continuing high rate of evaporation for plants and soil, has a positive effect on the quality of grapes grown in the area.

Notice of Proposed Rulemaking and TTB Finding

TTB published a notice of proposed rulemaking regarding the establishment of the Salado Creek viticultural area in the October 30, 2003, **Federal Register** as Notice No. 20 (68 FR 61776). In that notice, TTB requested comments by December 29, 2003. No comments were received. Under the authority of the Federal Alcohol Administration Act and part 4 of our regulations, we find that the submitted evidence supports the proposed viticultural area's establishment. Therefore, we establish the "Salado Creek" viticultural area effective 60-days from this document's publication date.

Regulatory Flexibility Act

We certify that this rule will not have a significant economic impact on a substantial number of small entities. This rule imposes no new reporting, recordkeeping, or other administrative requirement. Any benefit derived from the use of a viticultural area name is the result of a proprietor's efforts and consumer acceptance of wines from that area. Therefore, no regulatory flexibility analysis is required.

Executive Order 12866

This rule is not a significant regulatory action as defined by Executive Order 12866 (58 FR 51735). Therefore, it requires no regulatory assessment.

Drafting Information

The principal author of this document is N.A. Sutton, Regulations and Procedures Division, Alcohol and Tobacco Tax and Trade Bureau.

List of Subjects in 27 CFR Part 9

Wine.

The Final Rule

■ For the reasons discussed in the preamble, we amend 27 CFR, chapter 1, part 9 as follows:

PART 9—AMERICAN VITICULTURAL AREAS

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

Authority: 27 U.S.C. 205.

Subpart C—Approved American Viticultural Areas

■ 2. Subpart C is amended by adding § 9.163 to read as follows:

§ 9.163 Salado Creek.

(a) The name of the viticultural area described in this section is "Salado Creek".

(b) *Approved Maps.* The appropriate maps for determining the boundaries of the Salado Creek viticultural area are two 1:24,000 Scale USGS topographic maps. They are titled:

(1) Patterson, California Quadrangle,—Stanislaus Co., 7.5 Minute Series, edition of 1953; photorevised 1971, photoinspected 1978; and

(2) Crows Landing, California Quadrangle,—Stanislaus Co., 7.5 Minute Series, edition of 1952, photorevised 1980.

(c) *Boundaries.* The Salado Creek viticultural area is located in Stanislaus County, California, just southwest of the town of Patterson. The Salado Creek viticultural area boundary is as follows:

(1) Beginning on the Patterson Quadrangle map, section 19, T6S, R8E, at the intersection of Interstate Highway 5 and Fink Road, proceed northwest for 4.25 miles along Interstate 5 to its junction with an unnamed light duty road in section 35, T5S, R7E; then

(2) Follow the unnamed light duty road for approximately 0.45 miles, going east across the California Aqueduct and then north, to the road's intersection with the light duty road atop the levee on the east bank of the Delta-Mendota Canal in section 35, T5S, R7E; then

(3) Proceed southeast approximately 0.3 miles along the Delta-Mendota Canal levee road to its intersection with an unnamed unimproved road in section 35, T5S, R7E; then

(4) Proceed north and then east on the unimproved road for approximately 0.4 mile to its intersection with Baldwin Road and continue east on Baldwin Road approximately one mile, crossing Salado Creek, to the Baldwin Road's intersection with Ward Avenue at the eastern boundary line of section 36, T5S, R7E; then,

(5) Proceed north on Ward Avenue approximately 400 feet to its intersection with the 2nd Lift drainage canal in section 31, T5S, R8E; then

(6) Follow the 2nd Lift canal southeast approximately 0.75 miles to its intersection with Elfers Road in section 31, T5S, R8E; then

(7) Proceed east on Elfers Road approximately for 0.45 miles, crossing onto the Crows Landing Quadrangle map, to its intersection with an unnamed, unimproved road on the south side of Elfers Road that also marks the western boundary of section 6, T6S, R8E; then

(8) Proceed straight south on the unimproved road approximately one mile to its intersection with Marshall Road in section 6, T6S, R8E; then

(9) Follow Marshall Road straight west 1.1 miles, crossing onto the USGS Patterson map, to its intersection with Ward Avenue in section 6, T6S, R8E; then

(10) Proceed south 1.65 miles on Ward Avenue to its intersection with the California Aqueduct, then continue generally south approximately 1.4 miles along the aqueduct to its intersection with Fink Road in section 19, T6S, R8E; then

(11) Follow Fink Road northwest for approximately 0.5 miles, returning to the beginning point at the intersection of Interstate Highway 5 and Fink Road in section 19, T6S, R8E.

Signed: March 15, 2004.

Arthur J. Libertucci,

Administrator.

Approved: April 27, 2004.

Timothy E. Skud,

Deputy Assistant Secretary (Tax, Trade, and Tariff Policy).

[FR Doc. 04–14651 Filed 6–28–04; 8:45 am]

BILLING CODE 4810–31–P

DEPARTMENT OF THE TREASURY

Alcohol and Tobacco Tax and Trade Bureau

27 CFR Part 9

[T.D. TTB–14; Re: Notice No. 8]

RIN 1513–AA28

San Bernabe and San Lucas Viticultural Areas (2001R–170P)

AGENCY: Alcohol and Tobacco Tax and Trade Bureau, Treasury.

ACTION: Final rule; Treasury decision.

SUMMARY: This Treasury decision establishes the San Bernabe viticultural area and realigns the existing San Lucas viticultural area. Both viticultural areas are within the Monterey viticultural area in Monterey County, California, and within California's multi-county Central Coast viticultural area. The establishment of viticultural areas allows vintners to describe more accurately where their wines come from and enables consumers to better identify the wines they purchase.

EFFECTIVE DATE: August 30, 2004.

FOR FURTHER INFORMATION CONTACT: N. A. Sutton, Program Manager, Regulations and Procedures Division, Alcohol and Tobacco Tax and Trade Bureau, 6660 Delmonico Dr., #D422, Colorado Springs, CO 80919; telephone 415–271–1254.

SUPPLEMENTARY INFORMATION:

Background on Viticultural Areas

TTB Authority

The Federal Alcohol Administration Act (FAA Act) at 27 U.S.C. 205(e) requires that alcohol beverage labels provide the consumer with adequate information regarding a product's identity, while prohibiting the use of misleading information on such labels. The FAA Act also authorizes the Secretary of the Treasury to issue regulations to carry out the Act's provisions. The Alcohol and Tobacco Tax and Trade Bureau (TTB) administers these regulations.

Regulations in 27 CFR Part 4, Labeling and Advertising of Wine, allow the establishment of definitive viticultural areas and the use of their names as appellations of origin on wine labels and in wine advertisements. Title 27 CFR Part 9, American Viticultural Areas, contains the list of approved viticultural areas.

Definition

Title 27 CFR 4.25(e)(1) defines an American viticultural area as a delimited grape-growing region distinguishable by geographic features whose boundary has been delineated in subpart C of part 9. The establishment of viticultural areas allows the identification of regions where a given quality, reputation, or other characteristics of the wine is essentially attributable to its geographic origin. The establishment of viticultural areas allows vintners to describe more accurately the origin of their wines to consumers and helps consumers to identify the wines they purchase. Establishment of a viticultural area is neither an approval nor endorsement by TTB of the wine produced there.

Requirements

Section 4.25(e)(2) outlines the procedure for proposing an American viticultural area. Anyone interested may petition TTB to establish a grape-growing region as a viticultural area. The petition must include—

- Evidence that the proposed viticultural area is locally and/or nationally known by the name specified in the petition;
- Historical or current evidence that the boundaries of the proposed viticultural area are as specified in the petition;
- Evidence relating to the geographical features, such as climate, soils, elevation, physical features, etc., that distinguish the proposed area from surrounding areas;
- A description of the proposed viticultural area's specific boundaries, based on features found on maps approved by the United States Geological Survey (USGS); and
- A copy of the appropriate USGS map(s) with the boundaries prominently marked.

A petition requesting the modification of an established viticultural area must include the appropriate evidence and maps as described above to support the requested modification(s).

Impact on Current Wine Labels

Part 4 of the TTB regulations prohibits any label reference on a wine that suggests an origin other than the wine's true place of origin. With certain exceptions, the regulations also prohibit the use of brand names of viticultural significance, such as the name of a State, county, or viticultural area, unless the wine meets the appellation of origin requirements for the named geographic area.

With the establishment of the "San Bernabe" viticultural area, its name, like that of the existing "San Lucas" viticultural area, becomes a term of viticultural significance. Wine bottlers using "San Bernabe" or "San Lucas" in a brand name, including a trademark, or in another label reference, must ensure the product is eligible to use that viticultural area's name as an appellation of origin.

For a wine to be eligible to use a viticultural area name listed in part 9 of the TTB regulations as an appellation of origin, at least 85 percent of the grapes used to make the wine must have been grown within that viticultural area. If the wine is not eligible to use the viticultural area name and that name appears in the wine's brand name or in another label reference, the label is not in compliance and the bottler must change the brand name or other label reference and obtain approval of a new label.

Different rules apply if a wine has a brand name containing a viticultural area name that was used as a brand name on a label approved before July 7, 1986. See 27 CFR 4.39(i) for details.

San Bernabe and San Lucas Petitions

We received two petitions from Claude Hoover of Delicato Family Vineyards, Monterey, California, proposing the establishment of a new viticultural area to be named San Bernabe, and the realignment of the adjacent, established San Lucas viticultural area (27 CFR 9.56). Both viticultural areas are located in the Salinas Valley in central Monterey County, California. The two areas are within the Monterey viticultural area (27 CFR 9.98) and the multi-county Central Coast viticultural area (27 CFR 9.75).

The San Bernabe viticultural area encompasses 24,796 acres of predominantly rolling hills with sandy soils and 7,636 acres of vineyards. The realignment of the San Lucas viticultural area transfers 1,281 acres of rolling, sandy land from the northwestern San Lucas area to the southern San Bernabe area. This realignment avoids splitting a large vineyard between the two viticultural areas, prevents overlapping boundary lines between the two viticultural areas, and creates one common boundary line between the San Bernabe viticultural area and the San Lucas viticultural area.

Name Evidence

According to the 1991 publication of "Monterey County Place Names, A Geographical Dictionary," by Donald Thomas Clark, Father Pedro Font, a member of the California expedition of Spanish explorer DeAnza, documented the initial reference to San Bernabe on March 8, 1776. He wrote in his diary, "we had passed a spur of the Sierra de Santa Lucia * * *. The road at first runs through a spur of mountains, until it descends to a wide valley called the Cañada de San Bernabe." Eventually the area became known as "Rancho San Bernabe."

The Thompson Canyon and San Lucas USGS quadrangle maps prominently identify the area as San Bernabe. The relevant Thomas Guide labels this area Rancho San Bernabe. The TopoZone map Web site identifies this rural area as San Bernabe.

The 13,000-acre San Bernabe vineyard estate, owned by Delicato Family Vineyards, has 7,636 acres planted to grapes and sits almost entirely within the new viticultural area. A small portion of the vineyard estate, outside the San Bernabe viticultural area boundaries, is unplanted and unsuitable for grape cultivation. According to the Delicato Family Vineyards petition, the San Bernabe vineyard estate is recognized as the largest continuous vineyard estate under a single ownership in the free world.

Boundary Evidence

According to the 1991 "Monterey County Place Names, A Geographical Dictionary," the San Bernabe area land grants were given to Jesus Molina in 1841 and in 1842 to Petronillo Rios. In 1842 Rios bought the Molina land grant and the Rios family began raising cattle and crops on this land and producing wine from their own grapes. The Rios ranch, known as Rancho San Bernabe, eventually became a successful vineyard and wine producing property.

In the 1970s Prudential-Southdown purchased the San Bernabe acreage for vineyard development. In 1988 the Delicato family bought the San Bernabe vineyard for its premium and super-premium wine market potential. The San Bernabe vineyard estate occupies 52 percent of the viticultural area of the same name.

The San Bernabe viticultural area boundary line connects benchmarks, mountain peaks, and other U.S.G.S. map geographical features by using straight lines and several roads that follow the hilly terrain and soil changes.

The San Bernabe viticultural area shares portions of its west and southwest boundary lines with the surrounding Monterey viticultural area, which is, in turn, surrounded by the multi-county Central Coast viticultural area. The San Bernabe viticultural area shares its south boundary line with the realigned San Lucas viticultural area's northwestern boundary. The transfer of 1,281 acres of the San Lucas viticultural area to the San Bernabe viticultural area helps to better define the geographical differences between the established San Lucas area and the new San Bernabe area while preventing the split of an existing vineyard between the two viticultural areas.

Growing Conditions

Topography

The San Bernabe viticultural area is located immediately south of King City in the long Salinas Valley. The approximately 9-mile-long and 7-mile-wide viticultural area occupies the valley floor and rolling foothills, extending west from the Salinas River to the Santa Lucia Mountains. Unique viticultural qualities of the San Bernabe area include its climate, water quality, wind-produced eolian soils, and rolling hills. The 1,281 acres realigned from the San Lucas viticultural area possess similar eolian soils, rolling hills topography, and irrigation water quality as found in the new San Bernabe viticultural area.

Soils

In the San Bernabe viticultural area, grapes are grown below the 700-foot elevation level on rolling hills in wind-produced eolian soils. The Oceano, Garey, and Garey-Oceano complex eolian soil types, which are well to excessively well-drained, dominate the San Bernabe viticultural area. Small niches of alluvial soils, derived from the shale-based Santa Lucia Mountains, lie within the area and immediately to the north and south of the San Bernabe boundary lines.

The larger, surrounding Monterey viticultural area consists of only 1.6 percent eolian soils, and the alluvial Lockwood series soils dominate the adjacent San Lucas viticultural area. The realignment area possesses a predominance of the wind-produced eolian soils that contrast to the alluvial type soils of the San Lucas area. Above and west of the 700-foot contour line, the soils are derived from the shale-based Santa Lucia Mountains. The bench soils along the east boundary are common to the Salinas River area. East of the San Bernabe viticultural area boundary line, the Gabilan Mountain Range includes calcareous sandstone, shale, and siltstone, which come from a different source material, according to the petitioner.

Climate

The Salinas Valley forms a broad funnel for the strong, cool, afternoon marine winds coming off Monterey Bay during the warm months. The winds are drawn inland and south through the Salinas Valley by rising warm air that moderates the valley's high and low temperatures to varying degrees, producing a graduated effect in the valley. As a result, the San Bernabe area is warmer than viticultural areas to the north, and closer to Monterey Bay, and cooler than the adjoining San Lucas viticultural area to the immediate south.

The winds dissipate gradually as they travel inland from Monterey Bay and create a series of temperature-unique, grape-growing areas within the long Salinas Valley. San Bernabe, at 60 miles south of the Monterey Bay, averages a 30-degree daily temperature variation, while Salinas, at 17 miles from the Monterey Bay, averages a smaller 18-degree daily temperature variation.

The cool night air helps retain the grapes' acid and color, while the daily heat encourages ripeness and flavor. The San Bernabe area averages 30 frost-days annually, while Salinas, closer to Monterey Bay, averages only four frost-days.

More rain falls at the Salinas Valley's extreme north and south ends, with less falling in the region between, which includes the San Bernabe viticultural area. At the valley's north end, the city of Salinas averages 17.5 inches of annual rainfall, and, at the valley's south end, Paso Robles averages 19 inches. The San Bernabe area, between the two ends, averages only 13 inches of annual rainfall.

Water Resources

Irrigation water is used extensively in the San Bernabe viticultural area's vineyards. The water comes from area reservoirs and contains only small amounts of carbonates and nitrates, which benefits the grapevines and soil. Toward the Monterey Bay, water quality declines as nitrate and carbonate levels increase.

Notice of Proposed Rulemaking

Comments

TTB published a notice of proposed rulemaking regarding the establishment of the San Bernabe viticultural area and the realignment of the San Lucas viticultural area in the May 14, 2003, **Federal Register** as Notice No. 8 (68 FR 25851). In that notice, TTB requested comments by July 14, 2003, from all interested persons. No comments were received in response to this Notice No. 8.

TTB Finding

TTB finds that the evidence submitted with the petition supports the establishment of the proposed San Bernabe viticultural area and the realignment of the existing San Lucas viticultural area. Therefore, under the authority of the Federal Alcohol Administration Act and part 4 of our regulations, we establish the San Bernabe viticultural area and realign the San Lucas viticultural area as described in this final rule, effective 60-days from this document's publication.

Regulatory Analyses and Notices

Regulatory Flexibility Act

We certify that this rule will not have a significant economic impact on a substantial number of small entities. This rule imposes no new reporting, recordkeeping, or other administrative requirement. Any benefit derived from the use of a viticultural area name would be the result of a proprietor's efforts and consumer acceptance of wines from that area. Therefore, no regulatory flexibility analysis is required.

Executive Order 12866

This rule is not a significant regulatory action as defined by Executive Order 12866, 58 FR 51735. Therefore, it requires no regulatory assessment.

Drafting Information

The principal author of this document is N.A. Sutton (Colorado) Regulations and Procedures Division, Alcohol and Tobacco Tax and Trade Bureau.

List of Subjects in 27 CFR Part 9

Wine.

Authority and Issuance

■ For the reasons discussed in the preamble, we amend 27 CFR, chapter 1, part 9 as follows:

PART 9—AMERICAN VITICULTURAL AREAS

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

Authority: 27 U.S.C. 205.

Subpart C—Approved American Viticultural Areas

■ 2. Amend § 9.56 to revise paragraphs (c)(24) and (c)(25) and add paragraphs (c)(26) and (c)(27) to read as follows:

§ 9.56 San Lucas.

* * * * *

(c) *Boundary.* * * *.

* * * * *

(24) Then northeasterly approximately 1.3 miles to the 595-foot promontory, section 13, T21S, R8E (Espinosa Canyon Quadrangle);

(25) Then northeasterly approximately 0.6 mile to the intersection of a meandering, unnamed, light duty road and the fork of an intermittent stream, then continue meandering northeasterly, followed by southeasterly, approximately 1.1 miles to its intersection with an unnamed, light duty road south of the windmill, T21, R8E (Espinosa Canyon Quadrangle);

(26) Then northeasterly along the unnamed road approximately 0.6 mile to its intersection with the Salinas River, then continue 0.8 mile north in a straight line to benchmark 340, between U.S. Highway 101 and the Salinas River, in T21S, R9E (San Lucas Quadrangle);

(27) Then approximately 0.4 mile northwesterly in a straight line to the intersection with a water tank, then continues northeasterly in a straight line approximately 0.7 mile, and return to the point of beginning in the northwest corner of section 5, in T21S, R9E (San Lucas Quadrangle).

■ 3. Subpart C is amended by adding § 9.171 to read as follows:

§ 9.171 San Bernabe.

(a) *Name.* The name of the viticultural area described in this section is "San Bernabe".

(b) *Approved Maps.* The appropriate maps for determining the boundary of the San Bernabe viticultural area are four 1:24,000 scale, USGS topographic maps. They are titled:

(1) Thompson Canyon Quadrangle, California-Monterey County, 1949 (photorevised 1984);

(2) San Lucas Quadrangle, California-Monterey County, 1949 (photorevised 1984);

(3) Espinosa Canyon Quadrangle, California-Monterey County, 1949 (photorevised 1979); and

(4) Cosio Knob Quadrangle, California-Monterey County, 1949 (photorevised 1984);

(c) *Boundary.* The San Bernabe viticultural area is located in central Monterey County, south of King City, California, and west of U.S. Highway 101.

(1) The point of beginning on the Thompson Canyon Quadrangle is benchmark 304, located one-half mile southwest of King City, along the Salinas River, in Township 20 South (T20S) and Range 8 East (R8E). Proceed southeast in a straight line for 2.35 miles to benchmark 304, at the intersection of a trail and the 300–foot contour line, between U.S. Highway 101 and the Salinas River, in T20S and R8E (San Lucas Quadrangle); then

(2) Proceed southeast in a straight line for 2.9 miles to benchmark 336, between U.S. Highway 101 and the Salinas River, in T20S and R8E (San Lucas Quadrangle); then

(3) Proceed southeast in a straight line for 3 miles to benchmark 340, between U.S. Highway 101 and the Salinas River, in T21S and R9E (San Lucas Quadrangle); then

(4) Proceed south in a straight line for 0.8 mile to the intersection of the Salinas River and the Highway 198 bridge, in T21S and R9E (Espinosa Canyon Quadrangle); then

(5) Proceed southwest along Highway 198 for 0.6 mile to its intersection with an unnamed light duty road, in T21S and R9E (Espinosa Canyon Quadrangle); then

(6) Proceed northwest, followed by southwest, about 1.2 miles along the meandering, unnamed, light duty road to its intersection with the fork of an intermittent stream, in T21S and R8E (Espinosa Canyon Quadrangle); then

(7) Proceed southwest in a straight line for 0.6 mile to the 595-foot peak, Section 13, in T21S and R8E (Espinosa Canyon Quadrangle); then

(8) Proceed southwest in a straight line for 1.3 miles to the 788-foot peak, section 23, in T21S and R8E (Espinosa Canyon Quadrangle); then

(9) Proceed southwest in a straight line for 0.7 mile to the intersection of the unimproved road and jeep trail, east of the 73-degree longitudinal line, section 26, in T21S and R8E (Espinosa Canyon Quadrangle); then

(10) Proceed northwest in a straight line for 3.2 miles to the northwest corner of section 16, in T21S and R8E (Espinosa Canyon Quadrangle); then

(11) Proceed southwest in a straight line for 1.5 miles to the northeast corner of section 19, in T21S and R8E (Cosio Knob Quadrangle); then

(12) Proceed southwest in a straight line for 2.2 miles to the southwest corner of section 24, in T21S and R7E (Cosio Knob Quadrangle); then

(13) Proceed north in a straight line for 2 miles to the northwest corner of section 13, in T21S and R7E (Cosio Knob Quadrangle); then

(14) Proceed east in a straight line for 1 mile to the northeast corner of section 13, in T21S and R7E (Cosio Knob Quadrangle); then

(15) Proceed north in a straight line for 2 miles, along the R7E and R8E common boundary line, to the northwest corner of section 6, in T21S and R8E (Thompson Canyon Quadrangle); then

(16) Proceed east in a straight line for 0.1 mile to the southwest corner of section 31 and continue diagonally to the northeast corner of section 31, in T20S and R8E (Thompson Canyon Quadrangle); then

(17) Proceed west in a straight line for 2 miles to the southwest corner of section 25, in T20S and R7E (Thompson Canyon Quadrangle); then

(18) Proceed due north in a straight line for 0.1 mile to the intersection with a light duty road, named Pine Canyon Road, in section 25, and continue northeast along that road for 3.2 miles to its intersection with an unnamed secondary highway, north of benchmark 337, section 18, in T20S and R8E (Thompson Canyon Quadrangle); then

(19) Proceed northwest along the unnamed secondary highway for 0.3 mile to its intersection with U.S. Highway 101, in T20S and R8E (Thompson Canyon Quadrangle); then

(20) Proceed northeast along U.S. Highway 101 for 0.7 mile to benchmark 304, returning to the point of beginning (Thompson Canyon Quadrangle).

Signed: April 26, 2004.

Arthur J. Libertucci,

Administrator.

Approved: May 26, 2004.

Timothy E. Skud,

Deputy Assistant Secretary, (Tax, Trade, and Tariff Policy).

[FR Doc. 04–14652 Filed 6–28–04; 8:45 am]

BILLING CODE 4810–31–P

DEPARTMENT OF LABOR

Mine Safety and Health Administration

30 CFR Parts 56 and 57

Definitions for Surface and Underground Metal and Nonmetal Mines

AGENCY: Mine Safety and Health Administration (MSHA), Labor.

ACTION: Final rule; Technical amendment.

SUMMARY: This technical amendment moves several definitions from subparts B, C, E, H, M, and R of 30 CFR part 56, and from subparts B, C, E, H, M and T of 30 CFR part 57 to the general definitions section in subpart A of 30 CFR parts 56 and 57 respectively. This action eliminates redundancy and potential confusion with multiple definitions. It provides the metal and nonmetal mining community a central location in the CFR where most definitions applicable to surface or underground metal and nonmetal mines can be found. Definitions that have a specific application to a particular subpart have not been moved to subpart A.

DATES: *Effective Date:* June 29, 2004.

FOR FURTHER INFORMATION CONTACT: Marvin W. Nichols, Jr., Director, Office of Standards, Regulations and Variances, MSHA; 1100 Wilson Boulevard, Room 2350, Arlington, Virginia 22209–3939; telephone (202) 693–9440; facsimile (202) 693–9441; or e-mail: *nichols.marvin@DOL.gov.* This notice is available on the Internet at *http://www.msha.gov/REGSINFOR.HTM.*

SUPPLEMENTARY INFORMATION:

I. Discussion of Changes

This technical amendment moves several definitions from subparts B, C, E, H, M and R of 30 CFR part 56; and subparts B, C, E, H, M and T of 30 CFR part 57 to the general definition section of subpart A of 30 CFR parts 56 and 57. This action eliminates redundancy and potential confusion with multiple definitions. It provides the metal and nonmetal mining community a central location in the CFR where most definitions applicable to surface or underground metal and nonmetal mines can be found. Definitions that have a specific application to a particular subpart have not been moved to subpart A.

II. Procedural Matters

Administrative Procedures Act

The minor revisions contained in this notice are technical and nonsubstantive in nature. Accordingly, pursuant to 5 U.S.C. 553(b)(B) of the Administrative Procedures Act (APA), it has been determined that the notice and comment procedures do not apply to this action. For the same reason, it has been determined that in accordance with 5 U.S.C. 553(d), there is good cause to make these changes effective on the date of publication in the **Federal Register**.

III. Part 56

To eliminate potential confusion and redundancy with the definitions, the definition for *Explosive* found in § 56.2 and § 56.6000, has been combined and moved to § 56.2, the general definitions section for 30 CFR part 56. The definitions for *berm* and *mobil equipment* have been moved to § 56.2. Accordingly, § 56.9000 has now been deleted since *berm* and *mobile equipment* were the only definitions in that section.

IV. Part 57

To eliminate potential confusion and redundancy with the definitions, the definitions for *Auxiliary fan* found in § 57.2 and § 57.22002, *Booster fan* found in § 57.2 and § 57.22002, *Combustible material* found in § 57.4000 and § 57.22002, *Mobile equipment* found in § 57.9000 and § 57.14000, and *Noncombustible material* found in § 57.4000 and § 57.22002, have been combined and moved to § 57.2, the general definitions section to 30 CFR part 57. The definitions for *berm* and *mobile equipment* have been moved to § 57.2. Accordingly, § 57.9000 has now been deleted since *berm* and *mobile equipment* were the only two definitions in that section.

List of Subjects in 30 CFR Parts 56 and 57

Explosives, Ground control, Fire prevention, Loading, hauling, dumping, Machinery and equipment, Metal and nonmetal, Mine safety and health, Personnel hoisting.

Dated: June 23, 2004.

David Dye,

Deputy Assistant Secretary of Labor for Mine Safety and Health.

■ For the reasons set out in the preamble, and under the authority of the Federal Mine Safety and Health Act of 1977, MSHA is amending chapter I, parts 56 and 57 of title 30 of the Code of Federal Regulations as follows:

PART 56—[AMENDED]

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

Authority: 30 U.S.C. 811.

■ 2. Section 56.2 is revised to read as follows:

§ 56.2 Definitions.

The following definitions apply in this part. In addition definitions contained in any subpart of part 56 apply in that subpart. If inconsistent with the general definitions in this section, the definition in the subpart will apply in that subpart:

American Table of Distances means the current edition of "The American Table of Distances for Storage of Explosives" published by the Institute of Makers of Explosives.

Approved means tested and accepted for a specific purpose by a nationally recognized agency.

Attended means presence of an individual or continuous monitoring to prevent unauthorized entry or access.

Authorized person means a person approved or assigned by mine management to perform a specific type of duty or duties or to be at a specific location or locations in the mine.

Barricaded means obstructed to prevent the passage of persons, vehicles, or flying materials.

Barrier means a material object, or objects that separates, keeps apart, or demarcates in a conspicuous manner such as cones, a warning sign, or tape.

Berm means a pile or mound of material along an elevated roadway capable of moderating or limiting the force of a vehicle in order to impede the vehicle's passage over the bank of the roadway.

Blast area means the area in which concussion (shock wave), flying material, or gases from an explosion may cause injury to persons. In determining the blast area, the following factors shall be considered:

(1) Geology or material to be blasted.

(2) Blast pattern.

(3) Burden, depth, diameter, and angle of the holes.

(4) Blasting experience of the mine.

(5) Delay system, powder factor, and pounds per delay.

(6) Type and amount of explosive material.

(7) Type and amount of stemming.

Blast site means the area where explosive material is handled during loading, including the perimeter formed by the loaded blastholes and 50 feet (15.2 meters) in all directions from loaded holes. A minimum distance of 30 feet (9.1 meters) may replace the 50-foot (15.2-meter) requirement if the perimeter of loaded holes is demarcated with a barrier. The 50-foot (15.2-meter) and alternative 30-foot (9.1-meter) requirement also apply in all directions along the full depth of the hole.

Blasting agent means any substance classified as a blasting agent by the Department of Transportation in 49 CFR 173.114(a) (44 FR 31182, May 31, 1979) which is incorporated by reference..This document is available for inspection at each Metal and Nonmetal Safety and Health District Office of the Mine Safety and Health Administration, and may be obtained from the U.S. Government Printing Office, Washington, DC 20402.

Blasting area means the area near the blasting operations in which concussion or flying material can reasonably be expected to cause injury.

Blasting cap means a detonator which is initiated by a safety fuse.

Blasting circuit means the electrical circuit used to fire one or more electric blasting caps.

Blasting switch means a switch used to connect a power source to a blasting circuit.

Booster means any unit of explosive or blasting agent used for the purpose of perpetuating or intensifying an initial detonation.

Capped fuse means a length of safety fuse to which a blasting cap has been attached.

Capped primer means a package or cartridge of explosives which is specifically designed to transmit detonation to other explosives and which contains a detonator.

Circuit breaker means a device designed to open and close a circuit by nonautomatic means and to open the circuit automatically on a predetermined overcurrent setting without injury to itself when properly applied within its rating.

Combustible means capable of being ignited and consumed by fire.

Combustible liquids means liquids having a flash point at or above 100 °F (37.8 °C). They are divided into the following classes:

(1) Class II liquids—those having flash points at or above 100 °F (37.8 °C) and below 140 °F (60 °C).

(2) Class IIIA liquids—those having flash points at or above 140 °F (60 °C) and below 200 °F (93.4 °C).

(3) Class IIIB liquids—those having flash points at or above 200 °F (93.4 °C).

Combustible material means a material that, in the form in which it is used and under the conditions anticipated, will ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat. Wood, paper, rubber, and plastics are examples of combustible materials.

Company official means a member of the company supervisory or technical staff.

Competent person means a person having abilities and experience that fully qualify him to perform the duty to which he is assigned.

Conductor means a material, usually in the form of a wire, cable, or bus bar, capable of carrying an electric current.

Delay connector means a non-electric short interval delay device for use in delaying blasts which are initiated by detonating cord.

Detonating cord means a flexible cord containing a solid core of high explosives.

Detonator means any device containing a detonating charge that is used to initiate an explosive and includes but is not limited to blasting caps, electric blasting caps and nonelectric instantaneous or delay blasting caps.

Distribution box means a portable apparatus with an enclosure through which an electric circuit is carried to one or more cables from a single incoming feed line, each cable circuit being connected through individual overcurrent protective devices.

Electric blasting cap means a detonator designed for and capable of being initiated by means of an electric current.

Electrical grounding means to connect with the ground to make the earth part of the circuit.

Employee means a person who works for wages or salary in the service of an employer.

Employer means a person or organization which hires one or more persons to work for wages or salary.

Emulsion means an explosive material containing substantial amounts of oxidizers dissolved in water droplets, surrounded by an immiscible fuel.

Explosive means any substance classified as an explosive by the Department of Transportation in 49 CFR 173.53, 173.88, and 173.100 which are incorporated by reference. Title 49 CFR is available for inspection at each Metal and Nonmetal Safety and Health district office of the Mine Safety and Health Administration, and may be obtained from the U.S. Government Printing Office, Washington, DC 20402.

Explosive material means explosives, blasting agents, and detonators.

Face or bank means that part of any mine where excavating is progressing or was last done.

Fire resistance rating means the time, in minutes or hours, that an assembly of materials will retain its protective characteristics or structural integrity upon exposure to fire.

Flammable means capable of being easily ignited and of burning rapidly.

Flammable gas means a gas that will burn in the normal concentrations of oxygen in the air.

Flammable liquid means a liquid that has a flash point below 100 °F (37.8 °C), a vapor pressure not exceeding 40 pounds per square inch (absolute) at 100 °F (37.8 °C), and is known as a Class I liquid.

Flash point means the minimum temperature at which sufficient vapor is released by a liquid or solid to form a flammable vapor-air mixture at atmospheric pressure.

High potential means more than 650 volts.

Highway means any public street, public alley, or public road.

Hoist means a power driven windlass or drum used for raising ore, rock, or other material from a mine, and for lowering or raising persons and material.

Igniter cord means a fuse, cordlike in appearance, which burns progressively along its length with an external flame at the zone of burning, and is used for lighting a series of safety fuses in the desired sequence.

Insulated means separated from other conducting surfaces by a dielectric substance permanently offering a high resistance to the passage of current and to disruptive discharge through the substance. When any substance is said to be insulated, it is understood to be insulated in a manner suitable for the conditions to which it is subjected. Otherwise, it is, within the purpose of this definition, uninsulated. Insulating covering is one means for making the conductor insulated.

Insulation means a dielectric substance offering a high resistance to the passage of current and to a disruptive discharge through the substance.

Laminated partition means a partition composed of the following material and minimum nominal dimensions: ½-inch-thick plywood, ½-inch-thick gypsum wallboard, ⅛-inch-thick low carbon steel, and ¼-inch-thick plywood, bonded together in that order (IME–22 Box). A laminated partition also includes alternative construction materials described in the Institute of Makers of Explosives (IME) Safety Library Publication No. 22, "Recommendations for the Safe Transportation of Detonators in a Vehicle with other Explosive Materials," (May 1993), and the "Generic Loading Guide for the IME–22 Container," (October 1993). This incorporation by reference has been approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies are available at MSHA, 1100 Wilson Blvd., Room 2436, Arlington, Virginia 22209–3939, and at all Metal and Nonmetal Mine Safety and Health district offices, or available for inspection at the Office of the Federal Register, 800 North Capitol Street, NW., 7th Floor, suite 700, Washington, DC.

Lay means the distance parallel to the axis of the rope in which a strand makes one complete turn about the axis of the rope.

Loading means placing explosive material either in a blasthole or against the material to be blasted.

Low potential means 650 volts or less.

Magazine means a facility for the storage of explosives, blasting agents, or detonators.

Major electrical installation means an assemblage of stationary electrical equipment for the generation, transmission, distribution, or conversion of electrical power.

Mantrip means a trip on which persons are transported to and from a work area.

Mill includes any ore mill, sampling works, concentrator, and any crushing, grinding, or screening plant used at, and in connection with, an excavation or mine.

Misfire means the complete or partial failure of a blasting charge to explode as planned.

Mobile equipment means wheeled, skid-mounted, track-mounted, or rail-mounted equipment capable of moving or being moved.

Multipurpose dry-chemical fire extinguisher means an extinguisher having a rating of at least 2–A:10–B:C and containing a nominal 4.5 pounds or more of dry-chemical agent.

Noncombustible material means a material that, in the form in which it is used and under the conditions anticipated, will not ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat. Concrete, masonry block, brick, and steel are examples of noncombustible materials.

Non-electric delay blasting cap means a detonator with an integral delay element and capable of being initiated by miniaturized detonating cord.

Overburden means material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials or ores that are to be mined.

Overload means that current which will cause an excessive or dangerous temperature in the conductor or conductor insulation.

Permissible means a machine, material, apparatus, or device that has been investigated, tested, and approved by the Bureau of Mines or the Mine Safety and Health Administration and is maintained in permissible condition.

Potable water means water which shall meet the applicable minimum health requirements for drinking water established by the State or community in which the mine is located or by the Environmental Protection Agency in 40 CFR part 141, pages 169–182 revised as of July 1, 1977. Where no such requirements are applicable, the drinking water provided shall conform with the Public Health Service Drinking Water Standards, 42 CFR part 72, subpart J, pages 527–533, revised as of October 1, 1976. Publications to which references are made in this definition are hereby made a part hereof. These incorporated publications are available for inspection at each Metal and Nonmetal Mine Safety and Health District Office of the Mine Safety and Health Administration.

Powder chest means a substantial, nonconductive portable container equipped with a lid and used at blasting sites for explosives other than blasting agents.

Primer means a unit, package, or cartridge of explosives used to initiate other explosives or blasting agents, and which contains a detonator.

Reverse-current protection means a method or device used on direct-current circuits or equipment to prevent the flow of current in the reverse direction.

Rock fixture means any tensioned or nontensioned device or material inserted into the ground to strengthen or support the ground.

Roll protection means a framework, safety canopy or similar protection for the operator when equipment overturns.

Safety can means an approved container, of not over five gallons capacity, having a spring-closing lid and spout cover.

Safety fuse means a flexible cord containing an internal burning medium by which fire is conveyed at a continuous and uniform rate for the purpose of firing blasting caps or a black powder charge.

Safety switch means a sectionalizing switch that also provides shunt protection in blasting circuits between the blasting switch and the shot area.

Scaling means removal of insecure material from a face or highwall.

Secondary safety connection means a second connection between a conveyance and rope, intended to prevent the conveyance from running away or falling in the event the primary connection fails.

Shaft means a vertical or inclined shaft, a slope, incline or winze.

Short circuit means an abnormal connection of relatively low resistance, whether made accidentally or intentionally, between two points of different potential in a circuit.

Slurry (as applied to blasting). See "Water gel."

Storage facility means the entire class of structures used to store explosive materials. A "storage facility" used to store blasting agents corresponds to a BATF Type 4 or 5 storage facility.

Storage tank means a container exceeding 60 gallons in capacity used for the storage of flammable or combustible liquids.

Stray current means that portion of a total electric current that flows through paths other than the intended circuit.

Substantial construction means construction of such strength, material, and workmanship that the object will withstand all reasonable shock, wear, and usage, to which it will be subjected.

Suitable means that which fits, and has the qualities or qualifications to meet a given purpose, occasion, condition, function, or circumstance.

Travelway means a passage, walk or way regularly used and designated for persons to go from one place to another.

Water gel or *Slurry* (as applied to blasting) means an explosive or blasting agent containing substantial portions of water.

Wet drilling means the continuous application of water through the central hole of hollow drill steel to the bottom of the drill hole.

Working place means any place in or about a mine where work is being performed.

§ 56.3000 [Amended]

■ 3. Section 56.3000 is amended by removing the definition for *Rock fixture*.

§ 56.4000 [Amended]

■ 4. Section 56.4000 is amended by removing the following definitions: (1) *Combustible liquids;* (2) *Combustible material;* (3) *Fire resistance rating;* (4) *Flammable gas;* (5) *Flammable liquid;* (6) *Noncombustible material;* and (7) *Storage tank.*

§ 56.6000 [Amended]

■ 5. Section 56.6000 is amended by removing the following definitions: (1) *Attended;* (2) *Barrier;* (3) *Blast area;* (4) *Blast site;* (5) *Emulsion;* (6) *Explosive;* (7) *Explosive material;* (8) *Laminated partition;* (9) *Loading;* and (10) *Storage facility.*

§ 56.9000 [Removed]

■ 6. Section 56.9000 is removed.

§ 56.14000 [Amended]

■ 7. Section 56.14000 is amended by removing the definition for *Mobile equipment.*

PART 57—[AMENDED]

■ 8. The authority citation for part 57 continues to read as follows:

Authority: 30 U.S.C. 811.

■ 9. Section 57.2 is revised to read as follows:

§ 57.2 Definitions.

The following definitions apply to this part. In addition definitions contained in any subpart of part 57 apply in that subpart. If inconsistent with the general definitions in this section, the definition in the subpart will apply in that subpart:

Abandoned areas means areas in which work has been completed, no further work is planned, and travel is not permitted.

Abandoned mine means all work has stopped on the mine premises and an office with a responsible person in charge is no longer maintained at the mine.

Abandoned workings means deserted mine areas in which further work is not intended.

Active workings means areas at, in, or around a mine or plant where men work or travel.

American Table of Distances means the current edition of "The American Table of Distances for Storage of Explosives" published by the Institute of Makers of Explosives.

Approved means tested and accepted for a specific purpose by a nationally recognized agency.

Attended means presence of an individual or continuous monitoring to prevent unauthorized entry or access. In addition, areas containing explosive material at underground areas of a mine can be considered attended when all access to the underground areas of the mine is secured from unauthorized entry. Vertical shafts shall be considered secure. Inclined shafts or adits shall be considered secure when locked at the surface.

Authorized person means a person approved or assigned by mine management to perform a specific type of duty or duties or to be at a specific location or locations in the mine.

Auxilary fan means a fan used to deliver air to a working place off the main airstream; generally used with ventilation tubing.

Barricaded means obstructed to prevent the passage of persons, vehicles, or flying materials.

Barrier means a material object, or objects that separates, keeps apart, or demarcates in a conspicuous manner such as cones, a warning sign, or tape.

Berm means a pile or mound of material along an elevated roadway capable of moderating or limiting the force of a vehicle in order to impede the vehicle's passage over the bank of the roadway.

Blast area means the area in which concussion (shock wave), flying material, or gases from an explosion may cause injury to persons. In determining the blast area, the following factors, shall be considered:

(1) Geology or material to be blasted.

(2) Blast pattern.

(3) Burden, depth, diameter, and angle of the holes.

(4) Blasting experience of the mine.

(5) Delay system, powder factor, and pounds per delay.

(6) Type and amount of explosive material.

(7) Type and amount of stemming.

Blast site means the area where explosive material is handled during loading, including the perimeter formed by the loaded blastholes and 50 feet (15.2 meters) in all directions from loaded holes. A minimum distance of 30 feet (9.1 meters) may replace the 50-foot (15.2-meter) requirement if the perimeter of loaded holes is demarcated with a barrier. The 50-foot (15.2-meter) and alternative 30-foot (9.1-meter) requirements also apply in all directions along the full depth of the hole. In underground mines, at least 15 feet (4.6 meters) of solid rib, pillar, or broken rock can be substituted for the 50-foot (15.2-meter) distance. In underground mines utilizing a block-caving system or similar system, at least 6 feet (1.8 meters) of solid rib or pillar, including concrete reinforcement of at least 10 inches (254 millimeters), with overall dimensions of not less than 6 feet (1.8 meters) may be substituted for the 50-foot (15.2-meter) distance requirement.

Blasting agent means any substance classified as a blasting agent by the Department of Transportation in 49 CFR 173.114(a) (44 FR 31182, May 31, 1979) which is incorporated by reference. This document is available for inspection at each Metal and Nonmetal Mine Safety and Health District Office of the Mine Safety and Health Administration, and may be obtained from the U.S. Government Printing Office, Washington, DC 20402.

Blasting area means the area near blasting operations in which concussion or flying material can reasonably be expected to cause injury.

Blasting cap means a detonator which is initiated by a safety fuse.

Blasting circuit means the electrical circuit used to fire one or more electric blasting caps.

Blasting switch means a switch used to connect a power source to a blasting circuit.

Blowout means a sudden, violent, release of gas or liquid due to the reservoir pressure in a petroleum mine.

Booster means any unit of explosive or blasting agent used for the purpose of perpetuating or intensifying an initial detonation.

Booster fan means a fan installed in the main airstream or a split of the main airstream to increase airflow through a section or sections of a mine.

Capped fuse means a length of safety fuse to which a blasting cap has been attached.

Capped primer means a package or cartridge of explosives which is specifically designed to transmit detonation to other explosives and which contains a detonator.

Circuit breaker means a device designed to open and close a circuit by nonautomatic means and to open the circuit automatically on a predetermined overcurrent setting without injury to itself when properly applied within its rating.

Combustible means capable of being ignited and consumed by fire.

Combustible material means a material that, in the form in which it is used and under the conditions anticipated, will ignite, burn, support combustion or release flammable vapors when subjected to fire or heat. Wood, paper, rubber, and plastics are examples of combustible materials.

Company official means a member of the company supervisory or technical staff.

Competent person means a person having abilities and experience that fully qualify him to perform the duty to which he is assigned.

Conductor means a material, usually in the form of a wire, cable, or bus bar, capable of carrying an electric current.

Delay connector means a nonelectric short interval delay device for use in delaying blasts which are initiated by detonating cord.

Detonating cord means a flexible cord containing a solid core of high explosives.

Detonator means any device containing a detonating charge that is used to initiate an explosive and includes but is not limited to blasting caps, electric blasting caps and non-electric instantaneous or delay blasting caps.

Distribution box means a portable apparatus with an enclosure through which an electric circuit is carried to one or more cables from a single incoming feed line; each cable circuit being connected through individual overcurrent protective devices.

Electric blasting cap means a detonator designed for and capable of being initiated by means of an electric current.

Electrical grounding means to connect with the ground to make the earth part of the circuit.

Employee means a person who works for wages or salary in the service of an employer.

Employer means a person or organization which hires one or more persons to work for wages or salary.

Emulsion means an explosive material containing substantial amounts of oxidizers dissolved in water droplets, surrounded by an immiscible fuel.

Escapeway means a passageway by which persons may leave a mine.

Explosive means any substance classified as an explosive by the Department of Transportation in 49 CFR 173.53, 173.88 and 173.100 which are incorporated by reference. Title 49 CFR is available for inspection at each Metal and Nonmetal Mine Safety and Health District Office of the Mine Safety and Health Administration, and may be obtained from the U.S. Government Printing Office, Washington, DC 20402.

Face or bank means that part of any mine where excavating is progressing or was last done.

Fire resistance rating means the time, in minutes or hours, that an assembly of materials will retain its protective characteristics or structural integrity upon exposure to fire.

Flame spread rating means the numerical designation that indicates the extent flame will spread over the surface of a material during a specified period of time.

Flammable means capable of being easily ignited and of burning rapidly.

Flammable gas means a gas that will burn in the normal concentrations of oxygen in the air.

Flammable liquid a liquid that has a flash point below 100 °F (37.8 °C), a vapor pressure not exceeding 40 pounds per square inch (absolute) at 100 °F (37.8 °C), and is known as a Class I liquid.

Flash point means the minimum temperature at which sufficient vapor is released by a liquid or solid to form a flammable vapor-air mixture at atmospheric pressure.

Geological area means an area characterized by the presence of the same ore bodies, the same stratigraphic sequence of beds, or the same ore-bearing geological formation.

Highway means any public street, public alley or public road.

High potential means more than 650 volts.

Hoist means a power driven windlass or drum used for raising ore, rock, or other material from a mine, and for lowering or raising persons and material.

Igniter cord means a fuse, cordlike in appearance, which burns progressively along its length with an external flame at the zone of burning, and is used for lighting a series of safety fuses in the desired sequence.

Insulated means separated from other conducting surfaces by a dielectric substance permanently offering a high resistance to the passage of current and to disruptive discharge through the substance. When any substance is said to be insulated, it is understood to be insulated in a manner suitable for the conditions to which it is subjected. Otherwise, it is, within the purpose of this definition, uninsulated. Insulating covering is one means for making the conductor insulated.

Insulation means a dielectric substance offering a high resistance to the passage of current and to a disruptive discharge through the substance.

Laminated partition a partition composed of the following material and minimum nominal dimensions: ½-inch-thick plywood, ½-inch-thick gypsum wallboard, ⅛-inch-thick low carbon steel, and ¼-inch-thick plywood, bonded together in that order (IME–22 Box). A laminated partition also includes alternative construction materials described in the Institute of Makers of Explosives (IME) Safety Library Publication No. 22, "Recommendations for the Safe Transportation of Detonators in a Vehicle with other Explosive Materials," (May 1993), and the "Generic Loading Guide for the IME–22 Container," (October 1993). This incorporation by reference has been approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies are available at MSHA, 1100 Wilson Blvd., Room 2436, Arlington, Virginia 22209–3939, and at all Metal and Nonmetal Mine Safety and Health district offices, or available for inspection at the Office of the Federal Register, 800 North Capitol Street, NW., 7th Floor, suite 700, Washington, DC.

Lay means the distance parallel to the axis of the rope in which a strand makes one complete turn about the axis of the rope.

Loading means placing explosive material either in a blasthole or against the material to be blasted.

Low potential means 650 volts or less.

Magazine means a facility for the storage of explosives, blasting agents, or detonators.

Main fan means a fan that controls the entire airflow of the mine, or the airflow of one of the major air circuits.

Major electrical installation means an assemblage of stationary electrical equipment for the generation, transmission, distribution, or conversion of electrical power.

Mantrip means a trip on which persons are transported to and from a work area.

Mill includes any ore mill, sampling works, concentrator, and any crushing, grinding, or screening plant used at, and in connection with, an excavation or mine.

Mine atmosphere means any point at least 12 inches away from the back, face, rib, and floor in any mine; and additionally, in a Category IV mine, at least 3 feet laterally away from the collar of a borehole which releases gas into a mine.

Mine opening means any opening or entrance from the surface into a mine.

Misfire means the complete or partial failure of a blasting charge to explode as planned.

Mobile equipment means wheeled, skid-mounted, track-mounted, or rail-mounted equipment capable of moving or being moved.

Multipurpose dry-chemical fire extinguisher means an extinguisher having a rating of at least 2–A:10–B:C and containing a nominal 4.5 pounds or more of dry-chemical agent.

Noncombustible material means a material that, in the form in which it is used and under the conditions anticipated, will not ignite, burn, support combustion, or release flammable vapors when subjected to fire or heat. Concrete, masonry block, brick, and steel are examples of noncombustible materials.

Non-electric delay blasting cap means a detonator with an integral delay element and capable of being initiated by miniaturized detonating cord.

Outburst means the sudden, violent release of solids and high-pressure occluded gases, including methane in a domal salt mine.

Overburden means material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials or ores that are to be mined.

Overload means that current which will cause an excessive or dangerous temperature in the conductor or conductor insulation.

Permissible means a machine, material, apparatus, or device which has been investigated, tested, and approved by the Bureau of Mines or the Mine Safety and Health Administration, and is maintained in permissible condition.

Potable water means water which shall meet the applicable minimum health requirements for drinking water established by the State or community in which the mine is located or by the Environmental Protection Agency in 40 CFR part 141, pages 169–182 revised as of July 1, 1977. Where no such requirements are applicable, the drinking water provided shall conform with the Public Health Service Drinking Water Standards, 42 CFR part 72, subpart J, pages 527–533, revised as of October 1. 1976. Publications to which references are made in this definition are hereby made a part hereof. These incorporated publications are available for inspection at each Metal and Nonmetal Mine Safety and Health District Office of the Mine Safety and Health Administration.

Powder chest means a substantial, nonconductive portable container equipped with a lid and used at blasting sites for explosives other than blasting agents.

Primer means a unit, package, or cartridge of explosives used to initiate other explosives or blasting agents. and which contains a detonator.

Reverse-current protection means a method or device used on direct-current circuits or equipment to prevent the flow of current in a reverse direction.

Rock burst means a sudden and violent failure of overstressed rock resulting in the instantaneous release of large amounts of accumulated energy. Rock burst does not include a burst resulting from pressurized mine gases.

Rock fixture means any tensioned or nontensioned device or material inserted into the ground to strengthen or support the ground.

Roll protection means a framework, safety canopy or similar protection for the operator when equipment overturns.

Safety can means an approved container, of not over 5 gallons capacity, having a spring-closing lid and spout cover.

Safety fuse means a flexible cord containing an internal burning medium by which fire is conveyed at a continuous and uniform rate for the purpose of firing blasting caps or a black powder charge.

Safety switch means a sectionalizing switch that also provides shunt protection in blasting circuits between the blasting switch and the shot area.

Scaling means removal of insecure material from a face or highwall.

Secondary safety connection means a second connection between a conveyance and rope, intended to prevent the conveyance from running away or falling in the event the primary connection fails.

Shaft means a vertical or inclined shaft, a slope, incline, or winze.

Short circuit means an abnormal connection of relatively low resistance, whether made accidentally or intentionally, between two points of difference potential in a circuit.

Slurry (as applied to blasting). See "Water gel."

Storage facility means the entire class of structures used to store explosive materials. A "storage facility" used to store blasting agents corresponds to a BATF Type 4 or 5 storage facility.

Storage tank means a container exceeding 60 gallons in capacity used for the storage of flammable or combustible liquids.

Stray current means that portion of a total electric current that flows through paths other than the intended circuit.

Substantial construction means construction of such strength, material, and workmanship that the object will withstand all reasonable shock, wear, and usage to which it will be subjected.

Suitable means that which fits, and has the qualities or qualifications to meet a given purpose, occasion, condition, function, or circumstance.

Travelway means a passage, walk or way regularly used and designated for persons to go from one place to another.

Water gel or Slurry (as applied to blasting) means an explosive or blasting agent containing substantial portions of water.

Wet drilling means the continuous application of water through the central hole of hollow drill steel to the bottom of the drill hole.

Working level (WL) means any combination of the short-lived radon daughters in one liter of air that will result in ultimate emission of 1.3×10^5 MeV (million electron volts) of potential alpha energy, and exposure to these radon daughters over a period of time is expressed in terms of "working level months" (WLM). Inhalation of air containing a radon daughter concentration of 1 WL for 173 hours results in an exposure of 1 WLM."

Working place means any place in or about a mine where work is being performed.

§ 57.3000 [Amended]

■ 10. Section 57.3000 is amended by removing the definitions for *Rock burst* and *Rock fixture*.

§ 57.4000 [Amended]

■ 11. Section 57.4000 is amended by removing the following definitions for: (1) *Booster fan;* (2) *Combustible material;* (3) *Fire resistance rating;* (4) *Flame spread rating;* (5) *Flammable gas;* (6) *Flammable liquid;* (7) *Noncombustible material;* and (8) *Storage tank.*

§ 57.6000 [Amended]

■ 12. Section 57.6000 is amended by removing following the definitions for: (1) *Attended;* (2) *Barrier;* (3) *Blast area;* (4) *Blast site;* (5) *Emulsion;* (6) *Laminated partition;* (7) *Loading;* and (8) *Storage facility.*

§ 57. 9000 [Removed]

■ 13. Section 57.9000 is removed.

§ 57. 14000 [Amended]

■ 14. Section 57.14000 is amended by removing the definition for Mobile equipment.

§ 57. 22002 [Amended]

■ 15. Section 57.22002 is amended by removing the definitions for (1) *Abandoned areas;* (2) *Auxilary fan;* (3)

Blowout; (4) *Booster fan;* (5) *Combustible material;* (6) *Geological area;* (7) *Mine atmosphere;* (8) *Noncombustible material;* (9) *Outburst.*

[FR Doc. 04–14698 Filed 6–28–04; 8:45 am]

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DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 282

RIN 0790–AG89

Procedures for Settling Personnel and General Claims and Processing Advance Decision Requests

AGENCY: Defense Office of Hearings and Appeals, Office of the General Counsel of the Department of Defense.

ACTION: Final rule.

SUMMARY: This rule implements policy and prescribes procedures for processing and settling personnel and general claims and for processing requests for an advance decision. The Legislative Branch Appropriations Act of 1996 transferred to the Director of the Office of Management and Budget (OMB) the Comptroller General's authority to settle claims. The OMB Director subsequently delegated some of these authorities to the Department of Defense. Later, the General Accounting Office Act of 1996 codified many of these delegations to the Secretary of Defense and others and transferred to the OMB Director the authority of the Comptroller General to waive uniformed service member and employee debts arising out of the erroneous payment of pay or allowances exceeding $1,500. The OMB Director subsequently delegated the authority to waive such debts of uniformed service members and DoD employees to the Secretary of Defense. The Secretary of Defense further delegated his claims settlement and waiver authorities to the General Counsel. This rule implements the reassignment of the Comptroller General's former duties within the Department of Defense with little impact on the public.

EFFECTIVE DATE: May 12, 2004.

FOR FURTHER INFORMATION CONTACT: Michael Hipple, 703–696–8510.

SUPPLEMENTARY INFORMATION: A proposed rule was published Thursday, November 14, 2002 (67 FR 68957–68963). No comments were received.

Executive Order 12866, "Regulatory Planning and Review"

It has been determined that this rule is not a significant rule because it does not (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 serous inconsistency or otherwise interfere with an action taken or planned by another Agency; (3) materially alter the budgetary impact on 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 this Executive order.

Public Law 96–354, "Regulatory Flexibility Act"

It has been certified that this rule does not have a significant economic impact on a substantial number of small entities because this rule affects members of the Uniformed Services, Federal employees and transportation carriers and provides procedures by which their claims against the United States will be adjudicated. The same minimal requirements for submitting a claim are applicable to members and transportation carriers.

Public Law 96–511, "Paperwork Reduction Act"

It has been certified that this rule does not impose information collection requirements.

Section 202, Public Law 104–4, "Unfunded Mandates Reform Act"

It has been certified that this rule does not involve a Federal mandate that may result in the expenditure by State, local and tribal governments, in the aggregate, or by the private sector, of $100 million or more and that such rulemaking will not significantly or uniquely affect small governments.

Executive Order 13132, "Federalism"

It has been certified that this rule does not have federalism implications. This rule 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.

List of Subjects in 32 CFR Part 282

Administrative practice and procedure, Armed forces, Claims.

■ Accordingly, 32 CFR part 282 is added to subchapter M to read as follows:

PART 282—PROCEDURES FOR SETTLING PERSONNEL AND GENERAL CLAIMS AND PROCESSING ADVANCE DECISION REQUESTS

Sec.

Authority: 5 U.S.C. 552; 10 U.S.C. 2575; 10 U.S.C. 2771; 10 U.S.C. 4712; 10 U.S.C. 9712; 24 U.S.C. 420; 31 U.S.C. 3529; 31 U.S.C. 3702; 32 U.S.C. 714; and 37 U.S.C. 554.

§ 282.1 Purpose.

This part implements policy under 32 CFR part 281 and prescribes procedures for processing and settling personnel and general claims under 31 U.S.C. 3702, 10 U.S.C. 2575, 10 U.S.C. 2771, 24 U.S.C. 420, 10 U.S.C. 4712, 10 U.S.C. 9712, 37 U.S.C. 554, 32 U.S.C. 714 and for processing requests for an advance decision under 31 U.S.C. 3529.

§ 282.2 Applicability and scope.

This part applies to:

(a) The Office of the Secretary of Defense, the Military Departments, the Chairman of the Joint Chiefs of Staff, the Combatant Commands, the Office of the Inspector General of the Department of Defense, the Defense Agencies, the DoD Field Activities, and all other organizational entities in the Department of Defense (hereafter referred to collectively as "the DoD Components").

(b) The Coast Guard, when it is not operating as a Service in the Navy under agreement with the Department of Homeland Security, and the Commissioned Corps of the Public Health Service (PHS) and the National Oceanic and Atmospheric Administration (NOAA), under agreements with the Departments of Health and Human Services and Commerce (hereafter referred to collectively as "the non-DoD Components").

§ 282.3 Definitions.

(a) *Armed Forces.* The Army, the Navy, the Air Force, the Marine Corps, and the Coast Guard.

(b) *Claim.* A demand for money or property under one of the following statutes: 31 U.S.C. 3702, 10 U.S.C. 2575,

10 U.S.C. 2771, 24 U.S.C. 420, 10 U.S.C. 4712, 10 U.S.C. 9712, 37 U.S.C. 554, or 32 U.S.C. 714.

(c) *Committee.* The person or persons invested, by order of a proper court, with the guardianship of a minor or incompetent person and /or the estate of a minor or incompetent person.

(d) *Component Concerned.* The agency/activity (as well as the official designated by the Head of the agency/activity) required to perform the function or take the action indicated or from whose activity a claim arose.

(e) *Final Action.* A finding by the appropriate official under this part concerning a claim from which there is no right to appeal or request reconsideration, or concerning which the time limit prescribed in this part for submitting an appeal or request for reconsideration has expired without such a submission.

(f) *Member.* A member or former member of the Uniformed Services.

(g) *Secretary Concerned.* The Secretary of the Army, addressing matters concerning the Army. The Secretary of the Navy, addressing matters concerning the Navy, the Marine Corps, and the Coast Guard when it is operating as a Service in the Navy. The Secretary of the Air Force, addressing matters concerning the Air Force. The Secretary of Homeland Security, addressing matters concerning the Coast Guard when it is not operating as a Service in the Navy. The Secretary of Health and Human Services, addressing matters concerning the PHS. The Secretary of Commerce, addressing matters concerning the NOAA.

(h) *Settlement.* A claim and the amount due that is administratively determined to be valid.

(i) *Uniformed Services.* The Army, the Navy, the Air Force, the Marine Corps, the Coast Guard, and the Commissioned Corps of the PHS and the NOAA.

§ 282.4 Policy.

It is DoD policy that:

(a) Claims shall be settled and advance decisions rendered in accordance with all pertinent statutes and regulations, and after consideration of other relevant authorities.

(b) This part applies to certain claim settlement and advance decision functions that, by statute or delegation, are vested in the Department of Defense or the Secretary of Defense. Appendix B to this part describes the claims included under these functional authorities.

§ 282.5 Responsibilities.

(a) The *General Counsel of the Department of Defense* (GC, DoD), or designee, shall:

(1) Upon the request of the Director, Defense Office of Hearings and Appeals (DOHA), consult on, or render legal opinions concerning, questions of law that arise in the course of the performance of the Director's responsibilities under paragraph (b) of this section.

(2) Render advance decisions under 31 U.S.C. 3529 and oversee the submission of requests for an advance decision arising from the activity of a DoD Component that are addressed to the Director of the Office of Personnel Management or the Administrator General Services in accordance with this part.

(b) The *Director, Defense Office of Hearings and Appeals* (DOHA), or designee, under the GC, DoD (as the *Director, Defense Legal Services Agency*), shall:

(1) Consider, and grant or deny, a request by the Secretary concerned under 31 U.S.C. 3702(e) to waive the time limit for submitting certain claims in accordance with 32 CFR part 281 and this part.

(2) Consider appeals from an initial determination, and affirm, modify, reverse, or remand the initial determination in accordance with 32 CFR part 281, this part, and relevant DoD Office of General Counsel opinions.

(c) The *Heads of the DoD Components*, or designees, shall:

(1) Process claims under 31 U.S.C. 3702, 10 U.S.C. 2575, 10 U.S.C. 2771, 24 U.S.C. 420, 10 U.S.C. 4712, 10 U.S.C. 9712, 37 U.S.C. 554, and 32 U.S.C. 714 in accordance with this part.

(2) Ensure that requests for an advance decision that originate in their organizations are prepared and submitted in accordance with this part.

(3) Pay claims as provided in a final action in accordance with this part.

(d) The *Heads of the Non-DoD Components*, or designees, shall:

(1) Process claims under 31 U.S.C. 3702, 10 U.S.C. 2575, 10 U.S.C. 2771, or 37 U.S.C. 554 in accordance with this part.

(2) Ensure that requests for an advance decision that originate in their organizations are prepared and submitted in accordance with this part.

(3) Pay claims as provided in a final action in accordance with this part.

Appendix A to Part 282—Guidance

(a) *Submitting a claim.* The procedures a claimant must follow to submit a claim are at Appendix C to this part.

(b) *Processing a claim.* The procedures a DoD Component must follow in processing a claim are at Appendix D to this part.[1]

[1] Contact the appropriate non-DoD Component for the procedures it follows in processing a claim.

(c) *Appeals.* The procedures for appealing initial determinations are at Appendix E to this part.

(d) *Disposition of claims upon settlement in general.*

(1) The appropriate official for the Component concerned shall pay a claim in accordance with the final action concerning the claim.

(2) Where state law requires, a committee must be appointed for a minor or incompetent person in accordance with State law before payment may be made.

(e) *Requests for an advance decision.* Procedures for requesting an advance decision under 31 U.S.C. 3529 concerning the propriety of a payment or voucher certification related to claims addressed in this part are at Appendix F to this part.

(f) *Publication.* In accordance with 5 U.S.C. 552, the Director, DOHA, or designee, shall make redacted copies of responses to requests for reconsideration and advance decisions by the GC, DoD, or designee, available for public inspection and copying at DOHA's public reading room and on the worldwide web.

Appendix B to Part 282—Claims Description

The Secretary of Defense is authorized to perform the claims settlement and advance decision functions for claims under the following statutes:

(a) 31 U.S.C. 3702 concerning claims in general when there is no other settlement authority specifically provided for by law.[1]

(b) 10 U.S.C. 2575 concerning the disposition of unclaimed personal property on a military installation.

(c) 10 U.S.C. 2771 concerning the final settlement of accounts of deceased members of the Armed Forces (but not the National Guard).[2]

(d) 24 U.S.C. 420, 10 U.S.C. 4712, and 10 U.S.C. 9712 concerning the disposition of the effects of a deceased person who was subject to military law at a place or Command under the jurisdiction of the Army or the Air Force or of a deceased resident of the Armed Forces Retirement Home.

(e) 37 U.S.C. 554 concerning the sale of personal property of members of the Uniformed Services who are in a missing status.

[1] This includes claims involving Uniformed Services members' pay, allowances, travel, transportation, payment for unused accrued leave, retired pay, and survivor benefits, and claims for refund by carriers for amounts collected from them for loss or damage to property they transported at Government expense; also included are other claims arising from the activity of a DoD Component. However, the Director of the Office of Personnel Management performs these functions for claims involving civilian employees' compensation and leave; and the Administrator of General Services performs these functions for claims involving civilian employees' travel, transportation, and relocation expenses.

[2] Claims under this statute are actually settled under the authority in 31 U.S.C. 3702 because there is no specific settlement authority in the statute.

(f) 32 U.S.C. 714 concerning the final settlement of accounts of deceased members of the National Guard.[3]

Appendix C to Part 282—Submitting a Claim

(a) *Who May Submit a Claim.* Any person ("claimant") may submit a claim who has a demand for money or property against the Government under 31 U.S.C. 3702, 10 U.S.C. 2575, 10 U.S.C. 2771, 24 U.S.C. 420, 10 U.S.C. 4712, 10 U.S.C. 9712, 37 U.S.C. 554, or 32 U.S.C. 714.

(b) *Where to Submit a Claim.* A claimant must submit a claim to the Component concerned in accordance with guidance provided by that Component. A claim that is submitted somewhere other than to the Component concerned does not stop the running of the time limit in paragraph (f) of this Appendix. It is the claimant's responsibility to submit a claim properly.

(c) *Format of a Claim.* A claimant must submit a claim in the format prescribed by the Component concerned. It must be written and be signed by the claimant (in the case of a claim on behalf of a minor or incompetent person, there are additional requirements explained at paragraph (e) of this Appendix) or by the claimant's authorized agent or attorney (there are additional requirements explained at paragraph (d) of this Appendix). In addition, it should:

(1) Provide the claimant's mailing address.

(2) Provide the claimant's telephone number.

(3) State the amount claimed.

(4) State the reasons why the Government owes the claimant that amount.

(5) Have attached copies of documents referred to in the claim.

(6) Include or have attached statements (that are attested to be true and correct to the best of the individual's knowledge and belief) of the claimant or other persons in support of the claim.

(d) *Claim Submitted by Agent or Attorney.* In addition to the requirements in paragraph (c) of this Appendix, a claim submitted by the claimant's agent or attorney must include or have attached a duly executed power of attorney or other documentary evidence of the agent's or attorney's right to act for the claimant.

(e) *Claim Submitted on Behalf of a Minor or Incompetent Person.* In addition to the requirements in paragraph (c) of this Appendix:

(1) If a guardian or committee has not been appointed, a claim submitted on behalf of a minor or incompetent person must:

(i) State the claimant's relationship to the minor or incompetent person.

(ii) Provide the name and address of the person having care and custody of the minor or incompetent person.

(iii) Include an affirmation that any moneys received shall be applied to the use and benefit of the minor or incompetent person, and that the appointment of a guardian or committee is not contemplated.

(2) If a guardian or committee has been appointed, a claim on behalf of a minor or incompetent person must include or have attached a certificate of the court showing the appointment and qualification of the guardian or committee.

(f) *When to Submit a Claim.* A claimant must submit a claim so that it is received by the Component concerned within the time limit allowed by statute.

(1) Claimants must submit claims within these statutory time limits:[1]

(i) Claims on account of Treasury checks under 31 U.S.C. 3702(c) must be received within 1 year after the date of issuance.

(ii) Claims under 31 U.S.C. 3702 (b), 10 U.S.C. 2771 and 32 U.S.C. 714 must be received within 6 years of the date the claim accrued. (A claim accrues on the date when everything necessary to give rise to the claim has occurred.) The time limit for claims of members of the Armed Forces that accrue during war or within 5 years before war begins, is 6 years from the date the claim accrued or 5 years after peace is established, whichever is later.

(iii) Claims under 10 U.S.C. 2575(d)(3) must be received within 5 years after the date of the disposal of the property to which the claim relates.

(iv) Claims under 24 U.S.C. 420(d)(1), 10 U.S.C. 4712, and 10 U.S.C. 9712 must be received within 6 years after the death of the deceased resident.

(v) Claims under 37 U.S.C. 554(h) must be received before the end of the 5-year period from the date the net proceeds from the sale of the missing person's personal property are covered into the Treasury.

(2) The time limits set by statute may not be extended or waived.[2] Although the issue of timeliness normally shall be raised upon initial submission (as explained at Appendix D to this part, paragraph (b)), the issue may be raised at any point during the claim settlement process.

(g) *Claimant Must Prove the Claim.* The claimant must prove, by clear and convincing evidence, on the written record that the United States is liable to the claimant for the amount claimed. All relevant evidence to prove the claim should be presented when a claim is first submitted. In the absence of compelling circumstances, evidence that is presented at later stages of the administrative process will not be considered.

Appendix D to Part 282—Processing a Claim

(a) *Initial Component Processing.* Upon receipt of a claim, the Component concerned must:

(1) Date stamp the claim on the date received.

(2) Determine whether the claim was received within the required time limit (time limits are summarized at Appendix C to this part, paragraph (f)) and follow the procedures in paragraph (b) of this Appendix if the claim was not timely.

(3) Investigate the claim.

(4) Decide whether the claimant provided clear and convincing evidence that proves all or part of the claim.

(5) Issue an initial determination that grants the claim to the extent proved or denies the claim, as appropriate. The initial determination must state how much of the claim is granted and how much is denied, and must explain the reasons for the determination.

(6) Notify the claimant of the initial determination. The Component must send the claimant a copy of the initial determination and a notice that explains:

(i) The action the Component shall take on the claim, if the initial determination is or becomes a final action (the finality of an initial determination is explained at paragraph (c) of this Appendix); and

(ii) The procedures the claimant must follow to appeal an initial determination that denies all or part of the claim (those appeal procedures are explained at Appendix E to this part), if applicable.

(b) *Untimely Claims.* When the Component concerned determines that a claim was not received within the statutory time limit, the Component must make an initial determination of untimely receipt. (The statutory time limits are explained in Appendix C to this part, paragraph (f).)

(1) The initial determination must cite the applicable statute and explain the reasons for the finding of untimely receipt. The Component must send the initial determination to the claimant with a notice that:

(i) States the claim was not received within the statutory time limit and, therefore, may not be considered, unless that finding is reversed on appeal, and explains how the claimant may appeal the finding (those appeal procedures are explained at Appendix E to this part); and either

(ii) If the claim does not qualify under 31 U.S.C. 3702(e), states that the statutory time limit may not be extended or waived; or

(iii) If the claim does qualify under 31 U.S.C. 3702(e), states that the claim may be further considered only if the time limit is waived, and explains how the claimant may apply for a waiver. (Paragraph (d) of this Appendix explains which claims qualify and the procedures for applying for a waiver).

(2) Except in cases where a claimant has applied under paragraph (d) of this Appendix to request a waiver of the time limit, the Component must return the claim to the claimant when the initial determination becomes a final action with a notice that the finding in the initial determination is final and, therefore, the claim may not be considered. If the claim qualifies under 31 U.S.C. 3702(e), the notice must also state that the claimant may resubmit the claim with an application under paragraph (d) of this Appendix.

(c) *Finality of an Initial Determination.* An initial determination that grants all of a claim is a final action when it is issued. Otherwise, an initial determination (including one of untimely receipt) is a final action if the

[3] Claims under this statute are actually settled under the authority in 31 U.S.C. 3702 because there is no specific settlement authority in the statute.

[1] Under Section 501 *et seq.* of title 50 Appendix, United States Code, periods of active military service are not included in calculating whether a claim has been received within these statutory time limits.

[2] There is an exception for certain claims described in 31 U.S.C. 3702(e). In those cases, the Secretary of Defense may waive the time limits in paragraph (f)(1)(ii) of this Appendix. Appendix D of this part, paragraph (d), explains which claims qualify and the procedures that apply.

Component concerned does not receive an appeal within 30 days of the date of the initial determination (plus any extension of up to 30 additional days granted by the Component concerned for good cause shown).

(d) *Waiver of Certain Time Limits.* When the Component concerned determines that a claim was not received within the statutory time limit in 31 U.S.C. 3702(b) or (c), the claimant may request a waiver of the time limit. Waiver is permitted only for those claims that satisfy the requirements of 31 U.S.C. 3702(e).[1] This provision confers no right or entitlement on a claimant. It is solely within the discretion of the Secretary of Defense whether to grant such a waiver in a particular case.

(1) The claim must contain the information and documents that are generally required for claims (those requirements are explained at Appendix C to this part, paragraph (c)).

(2) The Component concerned must investigate the claim and make an initial determination concerning the merits of the claim.

(3) If the initial determination grants all or part of the claim, and if the Secretary concerned agrees with the determination, the Secretary may request or recommend that the time limit be waived.[2] Requests and recommendations must be in writing and signed by the Secretary concerned. (This authority may not be delegated below the level of an Assistant Secretary.)

(i) The Secretary concerned shall forward the request or recommendation to the following address: Defense Office of Hearings and Appeals, Claims Division, P.O. Box 3656, Arlington, VA 22203–1995.

(ii) The entire record concerning the claim, including the initial determination, must be attached to the request.

(4) The Director, DOHA, must review the request and the written record and must:

(i) Grant the request and waive the statutory time limit, if the Director finds that all or part of the claim has been proven. The Director may also modify the finding concerning the amount of the claim that has been proven.

(ii) Deny the request, if the Director finds that no part of the claim has been proven.

(iii) Notify the Secretary concerned and the claimant of the decision and the reasons for the findings.

(5) In the event the Director, DOHA, denies the request, or grants the request but modifies the finding concerning the amount of the claim proven, the Secretary concerned or the claimant may request reconsideration (the procedures are explained at Appendix E to this part). The Director's decision is a final action if the Director does not receive a request for reconsideration within 30 days of the date of the Director's decision (plus any extension of up to 30 additional days granted by the Director for good cause shown).

[1] When this part was issued, 31 U.S.C. 3702(e) allowed time limit waivers only for claims up to $25,000 for Uniformed Service member's pay, allowances, travel, transportation, payments for unused accrued leave, retired pay, and survivors benefits. Since 31 U.S.C. 3702(e) could be amended at any time to modify these restrictions, always consult the current provisions of that Section to determine which claims are included.

[2] 31 U.S.C. 3702(e) currently requires a Secretarial request only in the case of a claim by or with respect to a member of the Uniformed Services who is not under the jurisdiction of the Secretary of a Military Department. As a matter of policy, the Department of Defense currently requires a Secretarial recommendation in all other cases.

Appendix E to Part 282—Appeals

(a) *Who May Appeal.* A claimant may appeal if an initial determination denies all or part of a claim or finds that the claim was not received by the Component concerned within the time limit required by statute; however, the decision of the Secretary concerned not to request or recommend waiver of the time limit is not appealable except to the Secretary concerned, if the Secretary as a matter of discretion provides for such appeals.

(b) *When and Where to Submit an Appeal.* A claimant's appeal must be received by the Component concerned within 30 days of the date of the initial determination. The Component may extend this period for up to an additional 30 days for good cause shown. No appeal may be accepted after this time has expired. An appeal sent directly to the DOHA is not properly submitted.

(c) *Content of an Appeal.* No specific format is required; however, the appeal must be written and be signed by the claimant, the claimant's authorized agent, or the claimant's attorney. It also should:

(1) Provide the claimant's mailing address;

(2) Provide the claimant's telephone number;

(3) State the amount claimed on appeal, or that the appeal is from a finding of untimely receipt, whichever applies;

(4) Identify specific:

(i) Errors or omissions of material and relevant fact;

(ii) Legal considerations that were overlooked or misapplied; and

(iii) Conclusions that were arbitrary, capricious, or an abuse of discretion;

(5) Present evidence of the correct or additional facts alleged;

(6) Explain the reasons the findings or conclusions should be reversed or modified;

(7) Have attached copies of documents referred to in the appeal; and

(8) Include or have attached statements (that are attested to be true and correct to the best of the individual's knowledge and belief) by the claimant or other persons in support of the appeal.

(d) *Component's Review.* The Component concerned must review a claimant's appeal, and affirm, modify, or reverse the initial determination.

(1) If the appeal concerns the denial of all or part of the claim and the Component grants the entire claim, or grants the claim to the extent requested in the appeal, the Component must notify the claimant in writing and explain the action the Component shall take on the claim. This is a final action.

(2) If the appeal concerns the untimely receipt of the claim and the Component determines that the claim was received within the time limit required by statute, the Component must notify the claimant in writing and process the claim on the merits.

(3) In all other cases, the Component must forward the appeal to the DOHA in accordance with paragraph (e) of this Appendix. If the appeal concerns an initial determination of untimely receipt, the Component should not investigate, or issue an initial determination concerning, the merits of the claim before forwarding the appeal. The Component must prepare a recommendation and administrative report (as explained in paragraph (f) of this Appendix). The Component must send a copy of the administrative report to the claimant, with a notice that the claimant may submit a rebuttal to the Component (as explained in paragraph (g) of this Appendix).

(e) *Submission of Appeal to DOHA.* No earlier than 31 days after the date of the administrative report, or the day after the claimant's rebuttal period, as extended, expires, the Component must send the entire record along with the recommendation and the administrative report required by paragraph (f) of this Appendix to the following address: Defense Office of Hearings and Appeals, Claims Division, P.O. Box 3656, Arlington, Virginia 22203–1995.

The record sent to the DOHA shall include specific identification of any major policy issue(s) and a statement as to whether the amount in controversy exceeds $100,000 either in the instant claim or in the aggregate for directly related claims. If the amount in controversy exceeds $100,000, a full description of the financial impact shall be provided.

(f) *Recommendation and Administrative Report.* The recommendation and administrative report required by paragraph (d) of this Appendix must include the following:

(1) The name of the claimant;

(2) The Component's file reference number;

(3) The Component's recommendation (and the reasons for it) for the disposition of the claim;

(4) Relevant and material documents (such as correspondence, business records, and witness statements), as attachments; and

(5) Complete copies of regulations, instructions, memorandums of understanding, tariffs and/or tenders, solicitations, contracts, or rules cited by the claimant or the Component, if a copy has not been previously provided, or is not available readily via electronic means.

(g) *Claimant's Rebuttal.* A claimant may submit a written rebuttal, signed by the claimant or the claimant's agent or attorney, in response to the recommendation and administrative report. The rebuttal must be submitted to the Component within 30 days of the date of the recommendation and administrative report. The Component may grant an extension of up to an additional 30 days for good cause shown. The rebuttal should include:

(1) An explanation of the points and reasons for disagreeing with the report;

(2) The Component's file reference number;

(3) Any documents referred to in the rebuttal; and

(4) Statements (that are attested to be true and correct to the best of the individual's knowledge and belief) by the claimant or other persons in support of the rebuttal.

(h) *Action by the Component.* The Component must:

(1) Date stamp the claimant's rebuttal on the date it is received;

(2) Send the entire record to the DOHA, but no earlier than 31 days after the date of the report, or the day after the claimant's rebuttal period, as extended, expires (as explained in paragraph (e) of this Appendix).

(i) *DOHA Appeal Decision.* Except as provided in paragraph (p) of this Appendix, the DOHA must base its decision on the written record, including the recommendation and administrative report and any rebuttal by the claimant. The DOHA shall coordinate its decision in advance with the GC, DoD when the appeal decision affects:

(1) Major policy issues;

(2) Involves a claim that is quasi-contractual in nature and arises from the activity of a DoD Component, but the claim was not settled under usual acquisition procedures; or

(3) When the amounts in controversy exceed $100,000, either for the instant claim or in the aggregate for directly related claims. The written decision must:

(i) Affirm, modify, reverse, or remand the Component's determination (and, if the issue is untimely receipt and there is a finding that the claim was timely received, may either consider and decide the claim on the merits or return the claim to the Component concerned for investigation and initial determination on the merits);

(ii) State the amount of the claim that is granted and the amount that is denied and/or state that the claim was or was not received within the statutory time limit, as appropriate; and

(iii) Explain the reasons for the decision.

(j) *Processing After the Appeal Decision.* After issuing an appeal decision, the DOHA must:

(1) Send the claimant the decision and notify the claimant of:

(i) The appropriate Component action on the claim as a consequence of the decision, if it is or becomes a final action (as explained in paragraph (k) of this Appendix); and

(ii) The procedures under this appendix to request reconsideration (as explained in paragraphs (l) through (n) of this Appendix), if the decision does not grant the claim to the extent requested, or does not contain a finding of timely receipt, as the case may be.

(2) Notify the Component concerned of the decision, and of the appropriate Component action on the claim as a consequence of the decision.

(k) *Finality of a DOHA Appeal Decision.* An appeal decision that finds that the claim was timely received is a final action when issued. Otherwise, an appeal decision is a final action if the DOHA does not receive a request for reconsideration within 30 days of the date of the appeal decision (plus any extension of up to 30 additional days granted by the DOHA for good cause shown). **Note:** In the case of a DOHA appeal decision issued before the effective date of this part that denied all or part of the claim, a request for reconsideration by the GC, DoD may be submitted within 60 days of the effective date of this part. The GC, DoD shall consider such requests and affirm, modify, reverse, or remand the DOHA appeal decision. Requests for reconsideration by the GC, DoD received more than 60 days after the effective date of this part shall not be accepted. Requests must be submitted to the address in paragraph (e) of this Appendix. The provisions of paragraph (n) of this Appendix apply.

(l) *Who May Request Reconsideration.* A claimant or the Component concerned, or both, may request reconsideration of a DOHA appeal decision.

(m) *When and Where to Submit a Request for Reconsideration.* The DOHA must receive a request for reconsideration within 30 days of the date of the appeal decision.[1] The DOHA may extend this period for up to an additional 30 days for good cause shown. No request for reconsideration may be accepted after this time has expired. A request for reconsideration must be sent to the DOHA at the address in paragraph (e) of this Appendix.

(n) *Content of a Request for Reconsideration.* The requirements of paragraph (c) of this Appendix, concerning the contents of an appeal, apply to requests for reconsideration.

(o) *DOHA's Review of a Request for Reconsideration.*

(1) No earlier than 31 days after the date of the appeal decision, or the day after the last period for submitting a request, as extended, expires, the DOHA must:

(i) Consider a request or requests for reconsideration;

(ii) Affirm, modify, reverse, or remand the appeal decision (and, if the issue is untimely receipt and there is a finding that the claim was timely received, may either consider and decide the claim on the merits or return the claim to the Component concerned for investigation and initial determination on the merits);

(iii) Prepare a response that explains the reasons for the finding; and

(iv) Send the response to the claimant and the Component concerned and notify both of the appropriate action on the claim.

(2) The response is a final action. It is precedent in the consideration of all claims covered by this part unless otherwise stated in the document.

(p) *Consideration of Appeals and Requests for Reconsideration.* When considering an appeal or request for reconsideration, the DOHA may:

(1) Take administrative notice of matters that are generally known or are capable of confirmation by resort to sources whose accuracy cannot reasonably be questioned.

(2) Remand a matter to the Component with instructions to provide additional information.

Appendix F to Part 282—Requests for an Advance Decision

(a) *Who May Request an Advance Decision.* A disbursing or certifying official or the Head of a Component may request an advance decision on a question involving:

(1) A payment the disbursing official or Head of the Component shall make; or

(2) A voucher presented to a certifying official for certification.

(b) *Who May Render an Advance Decision.* The following officials are authorized to render an advance decision concerning the matters indicated:

(1) The Secretary of Defense for requests involving claims under:

(i) 31 U.S.C. 3702 for Uniformed Services members' pay, allowances, travel, transportation, retired pay, and survivor benefits, and by carriers for amounts collected from them for loss or damage to property they transported at Government expense.

(ii) 31 U.S.C. 3702 that are not described in paragraph (b)(1)(i) of this Appendix and that arise from the activity of a DoD Component, when there is no other settlement authority specifically provided by law.

(iii) 10 U.S.C. 2575, 10 U.S.C. 2771, 24 U.S.C. 420, 10 U.S.C. 4712, 10 U.S.C. 9712, 37 U.S.C. 554, and 32 U.S.C. 714. Appendix B to this part describes these claims.

(2) The Director of the Office of Personnel Management for requests involving claims for civilian employees' compensation and leave.

(3) The Administrator of General Services for requests involving claims for civilian employees' travel, transportation, and relocation expenses.

(c) *Where to Submit a Request.* All requests described in paragraph (b)(1) of this Appendix and all other requests arising from the activity of a DoD Component (even if addressed to an official outside the Department of Defense) must be sent through the General Counsel of the Component concerned to the following address: General Counsel, Department of Defense, 1600 Defense Pentagon, Washington, DC 20301–1600.

(d) *Content of a Request.* Requests for an advance decision must:

(1) Specifically request an advance decision pursuant to 31 U.S.C. 3529;

(2) Describe all the relevant facts;

(3) Explain the reasons (both factual and legal) the requester considers the proposed payment to be questionable;

(4) Have attached vouchers, if any, and copies of all other relevant documents relating to the proposed payment;

(5) Have attached a legal memorandum from the General Counsel of the Component concerned that discusses the legality of the proposed payment under the circumstances presented in the request; and

(6) Comply with any other requirements established by the Director of the Office of Personnel Management or the Administrator of General Services.

(e) *Advance Decisions.* The GC, DoD must take action under paragraphs (e)(1), (e)(2), or (e)(3) of this Appendix, whichever applies.

(1) If the request is described in paragraph (b)(1) of this Appendix, the GC, DoD must review the request and issue an advance decision, unless the GC, DoD elects to proceed under paragraph (e)(3) of this Appendix.

[1] With respect to appeal decisions issued before the effective date of this part, the request for reconsideration by the GC, DoD must be received by the DOHA within 60 days of the effective date of this part as explained in paragraph (k) of this Appendix.

(i) The GC, DoD must send the decision, through the General Counsel of the Component concerned, to the requester, and must send a copy of the decision to the Director, DOHA for publication according to Appendix A to this part, paragraph (f).

(ii) The decision is controlling in the case; the reliance of certifying and disbursing officials on it in their disposition of the case is evidence that those officials have exercised due diligence in the performance of their duties.

(iii) An advance decision is precedent in similar claims under this part unless otherwise stated in the decision.

(2) If the request is not described in paragraph (b)(1) of this Appendix, the GC, DoD must review the request and either:

(i) Forward the request to the appropriate advance decision authority and notify the requester of that action; or

(ii) Return the request, through the General Counsel of the Component concerned, to the requester, with a memorandum explaining that under existing legal authorities a request for an advance decision is not necessary. After considering the memorandum, the requester may resubmit the request, through the General Counsel of the Component concerned, to the GC, DoD. The GC, DoD must forward the request to the appropriate advance decision authority, and notify the requester of that action.

(3) If the request is described in paragraph (b)(1) of this Appendix, and the claim is for not more than $250, the GC, DoD may refer the request to the General Counsel, Defense Finance and Accounting Service (DFAS). The General Counsel, DFAS, shall review the request and issue an advance decision.

(i) The General Counsel, DFAS, must send the decision, through the General Counsel of the Component concerned, to the requester, and must send a copy of the decision to the GC, DoD.

(ii) The decision is controlling in the case; the reliance of certifying and disbursing officials on it in their disposition of the case is evidence that those officials have exercised due diligence in the performance of their duties.

(iii) An advance decision issued by the General Counsel, DFAS, under this paragraph is not precedent in similar claims under this part.

Dated: June 21, 2004.

Patricia L. Toppings,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 04–14650 Filed 6–28–04; 8:45 am]

BILLING CODE 5001–06–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[MD135–3099a; FRL–7671–4]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Control of Volatile Organic Compound Emissions From Portable Fuel Containers

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is taking direct final action to approve revisions to the Maryland State Implementation Plan (SIP). The revisions pertain to new emission standards for portable fuel containers. EPA is approving these revisions in accordance with the requirements of the Clean Air Act.

DATES: This rule is effective on August 30, 2004 without further notice, unless EPA receives adverse written comment by July 29, 2004. If EPA receives such comments, it will publish a timely withdrawal of the direct final rule in the **Federal Register** and inform the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by MD 135–3099 by one of the following methods:

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

B. *E-mail: morris.makeba@epa.gov.*

C. *Mail:* Makeba Morris, Chief, Air Quality Planning Branch, Mailcode 3AP21, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103.

D. *Hand Delivery:* At the previously-listed EPA Region III address. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. MD 135–3099. EPA's policy is that all comments received will be included in the public docket without change, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The Federal regulations.gov website is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Copies of the documents relevant to this action are available for public inspection during normal business hours at the Air Protection Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103; the Air and Radiation Docket and Information Center, U.S. Environmental Protection Agency, 1301 Constitution Avenue, NW., Room B108, Washington, DC 20460; and Maryland Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

FOR FURTHER INFORMATION CONTACT: Marilyn Powers, (215) 814–2308, or by e-mail at *powers.marilyn@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

In December 1999, the Environmental Protection Agency (EPA) determined that the State Implementation Plan (SIP) submittals for 10 areas, including the Baltimore and Philadelphia-Wilmington-Trenton severe nonattainment areas, required additional emission reductions in order for these areas to attain the one-hour ozone standard.

As part of a regional effort to address these emission reduction shortfalls in the Ozone Transport Region (OTR), the Ozone Transport Commission (OTC) developed control measures into model rules and estimated emission reductions that would result from their implementation. One of the model rules was for control of volatile organic compound (VOC) emissions from portable fuel containers. The OTC model rules were based on existing rules developed by the California Air Resources Board (CARB), which were analyzed and modified by the OTC workgroup to address emission reduction needs in the OTR. Implementation of these model rules will help OTR states attain and maintain the one-hour ozone standard and reduce eight-hour ozone levels.

II. Summary of SIP Revision

On March 8, 2002, the Maryland Department of the Environment submitted a formal revision to its SIP. The SIP revision consists of new regulation COMAR 26.11.13.07 Control of VOC Emissions from Portable Fuel Containers. This regulation applies statewide to any person who sells, supplies, offers for sale, or manufactures for sale portable fuel containers and/or spout for use in Maryland on or after January 1, 2003.

This regulation requires each portable fuel container and/or spout to meet the following requirements: (1) Have only one opening for both filling and pouring, (2) have an automatic shut-off to prevent overfill during refueling, (3) automatic closing and sealing of the container and/or spout when not dispensing fuel, (4) have a minimum flow rate and fill level, (5) meet a permeation standard, (6) have a manufacturer's warranty against defects, and (7) clearly display a label with the date of manufacture and identifying the container and/or spout as a spill proof system. Also included in the regulation are compliance testing requirements, exemptions, recordkeeping, and administrative requirements.

III. Final Action

EPA is approving a revision to the Maryland SIP that adds new regulation .07 under COMAR 26.11.13 to establishes VOC emission standards for portable fuel containers. Implementation of this rule will result in statewide emission reductions, and will help the ozone nonattainment areas in the state attain the one-hour ozone standard.

EPA is publishing this rule without prior proposal because the Agency views this as a noncontroversial amendment and anticipates no adverse comment. However, in the "Proposed Rules" section of today's **Federal Register**, EPA is publishing a separate document that will serve as the proposal to approve the SIP revision if adverse comments are filed. This rule will be effective on August 30, 2004 without further notice unless EPA receives adverse comment by July 29, 2004. If EPA receives adverse comment, EPA will publish a timely withdrawal in the **Federal Register** informing the public that the rule will not take effect. EPA will address all public comments in a subsequent final rule based on the proposed rule. EPA will not institute a second comment period on this action. Any parties interested in commenting must do so at this time.

IV. Statutory and Executive Order Reviews

A. General Requirements

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

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

B. Submission to Congress and the Comptroller General

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

C. Petitions for Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by August 30, 2004. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action to approve the Maryland's VOC emission standards for portable fuel containers, may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: May 27, 2004.

James W. Newsom,

Acting Regional Administrator, Region III.

■ 40 CFR part 52 is amended as follows:

PART 52—[AMENDED]

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

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

Subpart V—Maryland

■ 2. Section 52.1070 is amended by adding paragraph (c)(184) to read as follows:

§ 52.1070 Identification of plan.

* * * * *

(c) * * *

(184) Revisions to the Code of Maryland Administrative Regulations (COMAR) for the Control of VOC Emissions from Portable Fuel Containers submitted on March 8, 2002 by the Maryland Department of the Environment:

(i) Incorporation by reference.

(A) Letter of March 8, 2002 from the Maryland Department of the Environment transmitting an addition to Maryland's State Implementation Plan pertaining to the control of volatile organic compounds (VOC) emissions from portable fuel containers.

(B) Addition of new regulation .07 under COMAR 26.11.13—*Control of VOC Emissions from Portable Fuel Containers,* adopted by the Secretary of the Environment on December 21, 2001, and effective on January 21, 2002.

(ii) Additional Material.—Remainder of the State submittal pertaining to the revisions listed in paragraph (c)(184)(i) of this section.

[FR Doc. 04–14602 Filed 6–28–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 141 and 142

[OW–2003–0066; FRL–7779–4]

RIN 2040–AE58

National Primary Drinking Water Regulations: Minor Corrections and Clarification to Drinking Water Regulations; National Primary Drinking Water Regulations for Lead and Copper

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This rule makes minor changes to clarify and correct EPA's Drinking Water regulations. This rule clarifies typographical errors, inadvertent omissions, editorial errors, and outdated language in the final Long Term 1 Enhanced Surface Water Treatment Rule (LT1ESWTR), the Surface Water Treatment Rule, and other rules. In addition to these clarifications, EPA is adding optional monitoring for disinfection profiling and an earlier compliance date for some requirements in the LT1ESWTR, and a detection limit for the Uranium Methods.

Also, EPA is reinstating text that was inadvertently dropped from the Lead and Copper Rule which listed the facilities that must be sent public education brochures by a public water system that has exceeded the action level for lead or copper.

DATES: This final rule is effective on July 29, 2004, except for the amendment to § 141.85(c)(2)(iii) which is effective June 29, 2004. For purposes of judicial review, this final rule is promulgated as of 1 p.m., eastern time on July 13, 2004, as provided in 40 CFR 23.7.

ADDRESSES: EPA has established a docket for this action under Docket ID No. OW–2003–0066. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket.* Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the Water Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Avenue, NW., Washington DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Water Docket is (202) 566–2426. If you would like to schedule an appointment for access to docket material, please call (202) 566–2426.

FOR FURTHER INFORMATION CONTACT: For general information, contact the Safe Drinking Water Hotline, telephone (800) 426–4791. The Safe Drinking Water Hotline is open Monday through Friday, excluding legal holidays, from 9 a.m. to 5:30 p.m., eastern time. For technical inquiries, contact Tracy Bone, Office of Ground Water and Drinking Water, U. S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone: (202) 564–5257; fax: (202) 564–3767; e-mail address: *bone.tracy@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

Entities potentially regulated by this action are public water systems (PWS). The following table provides examples of the regulated entities under this rule. A public water system, as defined by section 1401 of the Safe Drinking Water Act (SDWA), is "a system for the provision to the public of water for human consumption through pipes or other constructed conveyances, if such system has at least fifteen service connections or regularly serves at least twenty-five individuals." EPA defines "regularly served" as receiving water from the system 60 or more days per year. Categories and entities potentially regulated by this action include the following:

Category	Examples of potentially regulated entities
State, Tribal and Local Government	State, tribal or local government-owned/operated water supply systems using ground water, surface water or mixed ground water and surface water.
Federal Government	Federally owned/operated community water supply systems using ground water, surface water or mixed ground water and surface water.
Industry	Privately owned/operated community water supply systems using ground water, surface water or mixed ground water and surface water.

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 the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in §§ 141.2 and 141.3 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

II. Changes and Clarifications

EPA is promulgating today, all of the changes and clarifications proposed on March 2, 2004 (69 FR 9781), with the exception of two proposed clarifications discussed in section F concerning calibration of turbiditimeters. Each clarification and change promulgated today is discussed under the heading of the drinking water rule that it amends (*e.g.*, LT1ESWTR). EPA is also promulgating today an additional clarification, which was not in the March 2, 2004, Minor Corrections and Clarification to Drinking Water Regulations proposal. This clarification is discussed in section III.

In addition to clarifications of typographical and editorial errors, EPA is revising the LT1ESWTR to add optional monitoring for disinfection profiling and an earlier compliance date for some requirements in that rule. EPA is also promulgating a detection limit for the uranium methods. These three changes are discussed first.

A. LT1ESWTR Compliance Date Change and Optional Monitoring for Disinfection Profiling

The final LT1ESWTR was published on January 14, 2002 (67 FR 1812). In § 141.502 of the LT1ESWTR, EPA directed PWSs to "comply with these requirements in this subpart beginning January 14, 2005, except where otherwise noted." Today's rule changes the compliance date from January 14, 2005, to January 1, 2005, in § 141.502 as well as in endnote 8 of Subpart Q, Appendix B. EPA's reasons for moving the compliance date forward by two weeks are set forth in the preamble to the proposed rule at 69 FR 9782.

EPA is also changing the compliance date in two additional sections, §§ 141.73(a)(4) and 141.170(d), which reference the January 14, 2005, date. These two citations should have been included in the March 2, 2004, proposal.

By changing § 141.502, the following 12 requirements will have a compliance deadline of January 1, 2005, instead of January 14, 2005: §§ 141.520, 141.521, 141.522, 141.550, 141.551, 141.552, 141.553, 141.560, 141.561, 141.562, 141.563, and 141.564. July 1, 2003 (or January 1, 2004, for systems serving fewer than 500 persons), remains the compliance date for §§ 141.530–141.536. March 15, 2002, remains the compliance date for § 141.511.

In addition to changing the compliance date, EPA is adding a sentence to § 141.531 to clarify that States may approve a more representative total trihalomethanes (TTHM) and haloacetic acids (five) (HAA5) data set (optional monitoring) to avoid the disinfection profile monitoring required in § 141.530. EPA's intent was to allow this flexibility in the final LT1ESWTR rule (67 FR 1820, January 14, 2002). EPA had failed to make this flexibility explicit in that regulation.

B. Detection Limit for Compliance Monitoring of Uranium

The December 7, 2000, final Radionuclides Rule (65 FR 76708) included a detection limit for gross alpha, radium-226 and radium-228, and reserved a place for a uranium detection limit in Table B at § 141.25(c)(1). In today's action, EPA is amending Table B at § 141.25(c)(1) to add a detection limit of 1 μg/L for uranium. Establishing a uranium detection limit permits States the flexibility to substantially reduce the number of compliance samples and the frequency of repeat monitoring for uranium.

C. Radionuclide Rule Clarifications

In addition to amending the detection limit for uranium, EPA is making two clarifications to the final Radionuclide Rule (December 7, 2000, 65 FR 76708). In § 141.26(b)(2)(iv), EPA is adding "screening level" to the first sentence. (Note also, that the second "beta" in this sentence is a typographical error, and under today's rule is being removed.) Similarly, EPA is clarifying in § 141.26(b)(5), that there are two screening levels by adding the word "appropriate" to the first sentence so that it reads "* * * exceeds the appropriate screening level * * *." In addition, in the text that proposed to revise § 141.26(b)(5), we inadvertently referenced a nonexistent Table E, "or Table E in 141.66(d)"—this reference is deleted in this final rule.

In § 141.26(b)(6), EPA is revising the citation "(b)(1)(ii)" to read "(b)(1)(i)," and is revising citation "(b)(2)(i)" to read "(b)(2)(iv)." These were typographical errors and should have been (b)(1)(i) and (b)(2)(iv), which refer to meeting the screening level requirements until the system meets the requirements for reduced monitoring.

D. LT1ESWTR Clarifications

In addition to changing the date in § 141.502 to reduce monitoring burden as well as to allow States to approve alternative data sets for optional monitoring in § 141.531, EPA is clarifying typographical errors in the final LT1ESWTR. In Subpart Q Appendix B, in endnotes 4 and 8, the year of publication for the Long Term 1 Enhanced Surface Water Treatment Rule is incorrectly identified as 2001 when it should be 2002. Also in endnote 4, the word "monthly" is misspelled. In § 141.530 EPA is removing the grammatically incorrect, plural "s" from "systems" in the sentence "If you are a subpart H community or non-transient non-community water systems which serves fewer * * *".

Two typographical errors are being corrected in § 141.534. In the introductory paragraph for § 141.534, EPA inadvertently omitted a reference to § 141.74(b)(3)(v), which provides tables for determining the appropriate CT99.9 value to calculate the inactivation ratio. EPA is changing the introductory paragraph of § 141.534 to: "Use the tables in § 141.74(b)(3)(v) to determine the appropriate CT99.9 value. Calculate the total inactivation ratio as follows, and multiply the value by 3.0 to determine log inactivation of *Giardia lamblia*:"

In the table in § 141.534(a)(2), EPA is changing the "3" to "Σ" in the CT calculation formula. EPA inadvertently changed the "Σ" to a "3" during a text file conversion.

In § 141.551(a)(2), EPA is adding a "t" to the "no" in "A value determined by the State (no to exceed 1 NTU) * * *". In § 141.551(b)(2), EPA is adding the word "Filtration" to the phrase "All other 'Alternative' " so that it matches related language in § 141.551(a)(2).

EPA is deleting the last sentence in the second column in the table in § 141.563(b), because it is redundant. Also in the same table in § 141.563(c), the first column contains a typographical error. The acronym "BTU" will read "NTU" (Nephelometric Turbidity Units).

In the table in § 141.570(b)(2), EPA is adding the phrase: "and the cause (if known) for the exceedance(s)" to the description of information to report under § 141.570(b)(2). As a result, the entire paragraph will read: "The filter number(s), corresponding date(s), and the turbidity value(s) which exceeded 1.0 NTU during the month, and the cause (if known) for the exceedance(s), but only if 2 consecutive measurements exceeded 1.0 NTU."

This action redesignates the LT1ESWTR special primacy text as § 142.16(p). In addition, EPA is revising a citation in § 142.16 (p)(2)(ii) to "141.536" to read "141.535." This was a typographical error and should have been "141.535," which refers to calculating inactivation.

E. Stage 1 Disinfectants and Disinfection Byproducts Rule

The Stage 1 Disinfectants and Disinfection Byproducts Rule was promulgated on December 16, 1998 (63 FR 69390). This rule required systems to measure and report, among other things, violations of maximum residual disinfectant levels (MRDLs), *see* § 141.134(c)(1)(iv) (see 63 FR 69422 and 69472). However, EPA failed to add compliance with the applicable MRDL to the compliance requirements in § 141.133(a)(3). EPA is correcting this, and the language in § 141.133(a)(3) now reads "If, during the first year of monitoring under § 141.132, any individual quarter's average will cause the running annual average of that system to exceed the MCL for total trihalomethanes, haloacetic acids (five), or bromate; or the MRDL for chlorine or chloramine, the system is out of compliance at the end of that quarter." The burden for this requirement was already accounted for in the approved Information Collection Request No. 1895.02.

Also, in the final Stage 1 Disinfectants and Disinfection Byproducts Rule, EPA incorrectly cited in § 142.14(d)(12)(iv) and § 142.14(d)(13) a reference to § 142.16(f). The reference for both sections is now being revised to read § 142.16(h)(2) and § 142.16(h)(5) respectively.

F. Surface Water Treatment Rule

The Surface Water Treatment Rule (SWTR) was promulgated on June 29, 1989 (54 FR 27486). In that final rule, EPA incorrectly cited in § 141.74(b)(4)(ii) a reference to § 142.72(a). This citation is being corrected to read § 141.72(a).

Today's rule does not include the proposed clarifications (March 2, 2004, 69 FR 9784) concerning the calibration of turbiditimeters in § 141.174(a) (Interim Enhanced Surface Water Treatment Rule (IESWTR)) and in § 141.560(b) (LT1ESWTR). EPA is deferring a decision on this clarification until additional information provided in a public comment can be evaluated.

EPA is changing all citations to § 141.74(a)(3) or (4) to § 141.74(a)(1), and all citations to § 141.74(a)(5) to § 141.74(a)(2) to reflect revisions to the SWTR as described in the proposal.

TABLE 1.—REFERENCES TO THE SURFACE WATER TREATMENT RULE

SWTR provisions with incorrect cross references	Amendment
141.71(a)(2)	"(a)(4)" to (a)(1)
141.71(c)(2)(i)	"(a)(4)" to (a)(1)
141.72(a)(3)	"(a)(5)" to (a)(2)
141.72(a)(4)(i)	"(a)(3)" to (a)(1) and "(a)(5)" to (a)(2)
141.72(a)(4)(ii)	"(a)(3)" to (a)(1)
141.72(b)(2),	"(a)(5)" to (a)(2)
141.72(b)(3)(i)	"(a)(5)" to (a)(2) and, "(a)(3)" to (a)(1)
141.72(b)(3)(ii)	"(a)(3)" to (a)(1)
141.73(a)(1)	"(a)(4)" to (a)(1)
141.73(a)(2)	"(a)(4)" to (a)(1)
141.73(b)(1)	"(a)(4)" to (a)(1)
141.73(b)(2)	"(a)(4)" to (a)(1)
141.73(c)(1)	"(a)(4)" to (a)(1)
141.73(c)(2)	"(a)(4)" to (a)(1)
141.74(b)(6)(ii)	"(a)(3)" to (a)(1)
141.74(c)(3)(i)	"(a)(3)" to (a)(1)
141.74(c)(3)(ii)	"(a)(3)" to (a)(1)
141.75(a)(2)(viii)(G)	"(a)(3)" to (a)(1)
141.75(b)(2)(iii)(G)	"(a)(3)" to (a)(1)

G. Filter Backwash Recycling Rule

The Filter Backwash Recycling Rule (FBRR) was promulgated on June 8, 2001 (66 FR 31086). EPA inadvertently provided incomplete citations in subpart Q, Appendix A of the Public Notification rule for the FBRR violations. In entry I.A.(8) of 40 CFR part 141, subpart Q, Appendix A, EPA is adding a "(c)" to the "MCL/MRDL/TT violations Citation" column of § 141.76; and, in the "Monitoring & testing procedure violations Citation" column EPA has added "(b), (d)" to § 141.76.

The FBRR preamble (66 FR 31086, 31094) explicitly states that violations of the recordkeeping and reporting portions of this treatment technique trigger public notification (PN) obligations under 40 CFR part 141, subpart Q. EPA is clarifying the PN rule by striking the reference to reporting violations in Appendix A, endnote 1, and explicitly adding §§ 141.76(b), (c) and (d) to the list of categories requiring reporting in Appendix A (previous reference was to the entire § 141.76).

H. Bottled Water

In a November 1995 final rule (60 FR 57132), the Food and Drug Administration (FDA) moved their standards of quality for bottled water from 21 CFR 103.35 to 21 CFR 165.110. EPA is correcting a reference in our regulations in § 142.62(g)(2) to reflect the updated citation of these FDA regulations.

I. Information Collection Rule

The Information Collection Rule (ICR) was promulgated on May 14, 1996 (61 FR 24354). The requirements promulgated in the ICR expired on December 31, 2000. As a result, the ICR requirements (referred to as subpart M—Information Collection Requirements (ICRs) for Public Water Systems) were removed from the Code of Federal Regulations in 2001. However, there were remaining references to the data collected as a result of the ICR in other sections of part 141 that refer to "subpart M." EPA is deleting the phrase "or subpart M of this part" from § 141.132(a)(5). EPA is not deleting or revising the other references to subpart M because the data collected under the ICR are still being used.

J. Phase V Rule

In the final Phase V Rule (July 17, 1992, 57 FR 31776), EPA published a list of Best Available Technologies (BATs) for cyanide, *see* § 141.62(c). EPA is making the list more specific as to the type of chlorination ("alkaline chlorination").

III. Correction in the Lead and Copper Rule Public Education Requirement

In this final version of the rule, EPA is reinstating the list of the facilities that must be sent public education brochures by a public water system that has exceeded the action level for lead or copper. This list was included in the final Lead and Copper Rule, in § 141.85(c)(2)(iii) (June 7, 1991, 56 FR 26460; 26555) and published in the Code of Federal Regulations (CFR) from 1991 to 1999. However, a technical drafting error in the way in which EPA drafted its language of amendment for revisions to the LCR in 2000 caused the Office of Federal Register to delete this text from the 2001 edition of the CFR (January 12, 2000, 65 FR 1950, 2007). Thus, the current CFR text contains only a requirement to deliver public education materials "to facilities and organizations, including the following:" with no text following the colon. To remedy this, EPA is reinstating the missing text, specifically subparagraphs (A) through (G). Section 141.85(c)(2)(iii) will once again read as follows:

(iii) Deliver pamphlets and/or brochures that contain the public education materials in paragraphs (a)(1)(ii) and (a)(1)(iv) of this section to facilities and organizations, including the following:

(A) Public schools, and/or local school boards;

(B) City or county health department;

(C) Women, Infants, and Children and/or Head Start Program(s) whenever available;

(D) Public and private hospitals and/or clinics;

(E) Pediatricians;

(F) Family planning clinics; and

(G) Local welfare agencies.

Section 553 of the Administrative Procedure Act, 5 U.S.C. 553(b)(B), provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing prior notice and an opportunity for public comment. EPA is reinstating the list of facilities that must be sent public education brochures by a public water system that has exceeded the action level for lead or copper. EPA has determined that there is "good cause" for making this rule change final without prior proposal and opportunity for comment because this list was the product of a prior notice-and-comment rulemaking, *see* (June 7, 1991, 56 FR 26502), it had appeared in the CFR for several years, the deletion was due solely to a technical drafting error in a subsequent rule, and the list is not controversial. Thus, additional notice and public comment is not necessary. EPA finds that this constitutes "good cause" under 5 U.S.C. 553(b)(B). For the same reasons, EPA is making this rule change effective upon publication. 5 U.S.C. 553(d)(3).

IV. 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 the regulatory action is "significant" and therefore subject to 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.

It has been determined that this rule is not a "significant regulatory action" under the terms of Executive Order 12866 and is therefore not subject to OMB review.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* This action modifies and clarifies existing regulations. It does not add monitoring, recordkeeping or reporting requirements.

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 are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small government jurisdictions.

Small entities are defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any "not-for-profit enterprise which is independently owned and operated and is not dominant in its field." However, the RFA also authorizes an agency to use alternative definitions for each category of small entity, "which are appropriate to the activities of the agency" after proposing the alternative definition(s) in the **Federal Register** and taking comment. 5 U.S.C. 601(3)–(5). In addition, to establish an alternative small business definition, agencies must consult with SBA's Chief Counsel for Advocacy.

For purposes of assessing the impacts of today's rule on small entities, EPA considered small entities to be public water systems serving 10,000 or fewer persons. This is the cut-off level specified by Congress in the 1996 Amendments to the Safe Drinking Water Act for small system flexibility provisions. As required by the RFA requirements, EPA proposed using this alternative definition in the **Federal Register**, (63 FR 7620, February 13, 1998), requested public comment, consulted with the Small Business Administration (SBA), and finalized in the alternative definition in the Consumer Confidence Reports regulation (63 FR 44511, August 19, 1998). As stated in that final rule, the alternative definition would be applied to this regulation as well.

The optional monitoring for disinfection profiling provides flexibility for PWSs complying with LT1ESWTR. The earlier compliance date will not increase the cost of complying with LT1ESWTR since the monitoring and reporting requirements are unchanged. By specifying the detection limit for uranium, States have the flexibility to waive some monitoring for PWSs with samples below the detection limit. This action will not add new requirements.

This final rule imposes no cost on any entities over and above those imposed by previously published drinking water rules. This action corrects and clarifies existing regulations.

After considering the economic impacts of today's final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by this final rule are public water systems serving 10,000 or fewer persons. We have determined that no number of small entities will experience an impact.

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, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Today's rule contains no Federal mandates (under the regulatory provisions of Title II of the UMRA) for State, local, or tribal governments or the private sector. This final rule imposes no enforceable duty on any State, local or tribal governments or the private sector. This action corrects and clarifies existing regulations. The optional monitoring for disinfection profiling provides flexibility for PWSs to comply with LT1ESWTR. The earlier compliance date will not increase the cost of complying with LT1ESWTR since the monitoring and reporting requirements are unchanged. By specifying the detection limit for uranium, EPA provides States with the flexibility to waive some monitoring for PWSs with samples below the detection limit. Thus, today's final rule is not subject to the requirements of sections 202 and 205 of the UMRA.

EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. This action corrects and clarifies existing regulations. Thus, today's proposed rule is not subject to the requirements of section 203 of the UMRA.

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 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 final 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. There is no cost to State and local governments, and the final rule does not preempt State law. This action corrects and clarifies existing regulations. The optional monitoring for disinfection profiling provides flexibility for PWSs to comply with LT1ESWTR. The earlier compliance date will not increase the cost of complying with LT1ESWTR since the monitoring and reporting requirements are unchanged. By specifying the detection limit for uranium, States have the flexibility to waive some monitoring for PWSs with samples below the detection limit. Thus, Executive Order 13132 does not apply to this final 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 solicited comment on the 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." "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."

This final rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in Executive Order 13175. There is no cost to tribal governments, and the rule does not preempt tribal law. This action corrects and clarifies existing regulations. Thus, Executive Order 13175 does not apply to this rule. Moreover, in the spirit of Executive Order 13175, and consistent with EPA policy to promote communications between EPA and tribal governments, EPA specifically solicited comment on the proposed rule from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health & 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, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because the Agency does not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This rule is not subject to Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)) because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

As noted in the proposed rule, section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory 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, 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.

This action does not involve technical standards. Therefore, EPA did not consider the use of any voluntary consensus standards.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective July 29, 2004, except for the amendment to § 141.85(c)(2)(iii) which is effective June 29, 2004.

List of Subjects

40 CFR Part 141

Environmental protection, Chemicals, Indians-lands, Intergovernmental relations, Radiation protection, Reporting and recordkeeping requirements, Water supply.

40 CFR Part 142

Environmental protection, Administrative practice and procedure, Chemicals, Indians-lands, Radiation protection, Reporting and recordkeeping requirements, Water supply.

Dated: June 22, 2004.

Michael O. Leavitt,

Administrator.

■ For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 141—NATIONAL PRIMARY DRINKING WATER REGULATIONS

■ 1. The authority citation for part 141 continues to read as follows:

Authority: 42 U.S.C. 300f, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–4, 300j–9, and 300j–11.

§ 141.25 [Amended]

■ 2. Section 141.25(c)(1) is amended in the entry for uranium in the second column of Table B by removing the word "reserve" and adding in it's place "1 µg/L".

■ 3. Section 141.26 is amended as follows:

■ a. Revise paragraphs (b)(2)(iv) and (b)(5); and

■ b. In paragraph (b)(6) remove the citation "(b)(1)(ii)" and add in its place "(b)(1)(i)" and remove the citation "(b)(2)(i)" and add in its place "(b)(2)(iv)".

The revisions read as follows:

§ 141.26 Monitoring frequency and compliance requirements for radionuclides in community water systems.

* * * * *

(b) * * *

(2) * * *

(iv) If the gross beta particle activity minus the naturally occurring potassium-40 beta particle activity at a sampling point has a running annual average (computed quarterly) less than or equal to 15 pCi/L (screening level), the State may reduce the frequency of monitoring at that sampling point to every 3 years. Systems must collect the same type of samples required in paragraph (b)(2) of this section during the reduced monitoring period.

* * * * *

(5) If the gross beta particle activity minus the naturally occurring potassium-40 beta particle activity exceeds the appropriate screening level, an analysis of the sample must be performed to identify the major radioactive constituents present in the sample and the appropriate doses must be calculated and summed to determine compliance with § 141.66(d)(1), using the formula in § 141.66(d)(2). Doses must also be calculated and combined for measured levels of tritium and strontium to determine compliance.

* * * * *

§ 141.62 [Amended]

■ 4. Section 141.62(c) is amended as follows:

■ a. In the Table "BAT FOR INORGANIC COMPOUNDS LISTED IN SECTION 141.62(b)" amend the entry for "cyanide" by replacing the "10" with "13"; and

■ b. In the list "Key to BATS in Table 1", add to the end of the list, "13 = Alkaline Chlorination (pH ≥ 8.5)".

§ 141.71 [Amended]

■ 5. Section 141.71 is amended as follows:

■ a. In paragraph (a)(2) introductory text remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)" and

■ b. In paragraph (c)(2)(i) remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)".

§ 141.72 [Amended]

■ 6. Section 141.72 is amended as follows:

■ a. In paragraph (a)(3) remove the citation "§ 141.74(a)(5)" and add in its place "§ 141.74(a)(2)";

■ b. In paragraph (a)(4)(i) remove the citation "§ 141.74(a)(5)" and add in its place "§ 141.74(a)(2)" and remove the citation "§ 141.74(a)(3)" and add in its place "§ 141.74(a)(1)";

■ c. In paragraph (a)(4)(ii) remove the citation "§ 141.74(a)(3)" and add in its place "§ 141.74(a)(1)";

■ d. In paragraph (b)(2) remove the citation "§ 141.74(a)(5)" and add in its place "§ 141.74(a)(2)";

■ e. In paragraph (b)(3)(i) remove the citation "§ 141.74(a)(5)" and add in its place "§ 141.74(a)(2)", remove the citation "§ 141.74(a)(3)" and add in its place "§ 141.74(a)(1)"; and

■ f. In paragraph (b)(3)(ii) remove the citation "§ 141.74(a)(3)" and add in its place "§ 141.74(a)(1)".

§ 141.73 [Amended]

■ 7. Section 141.73 is amended as follows:

■ a. In paragraph (a)(1) remove both citations "§ 141.74(a)(4)" and add in their place "§ 141.74(a)(1)";

■ b. In paragraph (a)(2) remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)";

■ c. In paragraph (a)(4) remove the date "January 14, 2005" and add in its place "January 1, 2005";

■ d. In paragraph (b)(1) remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)";
■ e. In paragraph (b)(2) remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)";
■ f. In paragraph (c)(1) remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)"; and
■ g. In paragraph (c)(2) remove the citation "§ 141.74(a)(4)" and add in its place "§ 141.74(a)(1)".

§ 141.74 [Amended]

■ 8. Section 141.74 is amended as follows:
■ a. In paragraph (b)(4)(ii) remove the citation "§ 142.72(a)" and add in its place "§ 141.72(a)";
■ b. In paragraph (b)(6)(ii) remove the citation "(a)(3)" and add in its place "(a)(1)";
■ c. In paragraph (c)(3)(i) remove the citation "(a)(3)" and add in its place "(a)(1)"; and
■ d. In paragraph (c)(3)(ii) remove the citation "(a)(3)" and add in its place "(a)(1)".

§ 141.75 [Amended]

■ 9. Section 141.75 is amended as follows:
■ a. In paragraph (a)(2)(viii)(G) remove the citation "§ 141.74(a)(3)" and add in its place "§ 141.74(a)(1)"; and
■ b. In paragraph (b)(2)(iii)(G) remove the citation "§ 141.74(a)(3)" and add in its place "§ 141.74(a)(1)".
■ 10. Amend § 141.85 by adding paragraphs (c)(2)(iii) (A) through (G) to read as follows:

§ 141.85 Public education and supplemental monitoring requirements.

* * * * *

(c) * * *
(2) * * *
(iii) * * *
(A) Public schools, and/or local school boards;
(B) City or county health department;
(C) Women, Infants, and Children and/or Head Start Program(s) whenever available;
(D) Public and private hospitals and/or clinics;
(E) Pediatricians;
(F) Family planning clinics; and
(G) Local welfare agencies.

* * * * *

§ 141.132 [Amended]

■ 11. Section 141.132 is amended in paragraph (a)(5) by removing the reference to "or subpart M of this part".
■ 12. In § 141.133 revise paragraph (a)(3) to read as follows:

§ 141.133 Compliance requirements.

(a) * * *
(3) If, during the first year of monitoring under § 141.132, any individual quarter's average will cause the running annual average of that system to exceed the MCL for total trihalomethanes, haloacetic acids (five), or bromate; or the MRDL for chlorine or chloramine, the system is out of compliance at the end of that quarter.

* * * * *

§ 141.170 [Amended]

■ 13. In paragraph (d) remove the date "January 14, 2005" and add in its place "January 1, 2005".

Appendix A to Subpart Q of Part 141 [Amended]

■ 14. In Subpart Q, Appendix A is amended as follows:
■ a. In entry I.A.(8) remove the citation in the third column "141.76" and add in its place "141.76(c)" and remove the citation in the fifth column "141.76" and add in its place "141.76 (b), (d)".
■ b. Amend endnote 1 by removing the words "reporting violations and" from the first parenthetical phrase.
■ 15. In Subpart Q, Appendix B revise endnotes 4 and 8 to read as follows:

Appendix B to Subpart Q of Part 141—Standard Health Effects Language for Public Notification

* * * * *

[4] There are various regulations that set turbidity standards for different types of systems, including 40 CFR 141.13, and the 1989 Surface Water Treatment Rule, the 1998 Interim Enhanced Surface Water Treatment Rule and the 2002 Long Term 1 Enhanced Surface Water Treatment Rule. The MCL for the monthly turbidity average is 1 NTU; the MCL for the 2-day average is 5 NTU for systems that are required to filter but have not yet installed filtration (40 CFR 141.13).

* * * * *

[8] There are various regulations that set turbidity standards for different types of systems, including 40 CFR 141.13, the 1989 Surface Water Treatment Rule (SWTR), the 1998 Interim Enhanced Surface Water Treatment Rule (IESWTR) and the 2002 Long Term 1 Enhanced Surface Water Treatment Rule (LT1ESWTR). For systems subject to the IESWTR (systems serving at least 10,000 people, using surface water or ground water under the direct influence of surface water), that use conventional filtration or direct filtration, after January 1, 2002, the turbidity level of a system's combined filter effluent may not exceed 0.3 NTU in at least 95 percent of monthly measurements, and the turbidity level of a system's combined filter effluent must not exceed 1 NTU at any time. Systems subject to the IESWTR using technologies other than conventional, direct, slow sand, or diatomaceous earth filtration must meet turbidity limits set by the primacy agency. For systems subject to the LT1ESWTR (systems serving fewer than 10,000 people, using surface water or ground water under the direct influence of surface water) that use conventional filtration or direct filtration, after January 1, 2005, the turbidity level of a system's combined filter effluent may not exceed 0.3 NTU in at least 95 percent of monthly measurements, and the turbidity level of a system's combined filter effluent must not exceed 1 NTU at any time. Systems subject to the LT1ESWTR using technologies other than conventional, direct, slow sand, or diatomaceous earth filtration must meet turbidity limits set by the primacy agency.

* * * * *

■ 16. Revise § 141.502 to read as follows:

§ 141.502 When must my system comply with these requirements?

You must comply with these requirements in this subpart beginning January 1, 2005, except where otherwise noted.

§ 141.530 [Amended]

■ 17. In § 141.530 in the second sentence, revise "water systems" to read "water system".

■ 18. Amend § 141.531 by adding the following sentence to the end of the section, to read as follows:

§ 141.531 What criteria must a State use to determine that a profile is unnecessary?

* * * Your State may approve a more representative TTHM and HAA5 data set to determine these levels.

■ 19. Section 141.534 is amended as follows:
■ a. By revising the introductory paragraph,
■ b. In the table in paragraph (a)(2), remove the "3" and add in its place "Σ".

§ 141.534 How does my system use this data to calculate an inactivation ratio?

Use the tables in § 141.74(b)(3)(v) to determine the appropriate CT99.9 value. Calculate the total inactivation ratio as follows, and multiply the value by 3.0 to determine log inactivation of *Giardia lamblia:*

* * * * *

§ 141.551 [Amended]

■ 20. Section 141.551 is amended as follows:
■ a. In paragraph (a)(2) remove "no" and add in its place "not"; and
■ b. In paragraph (b)(2) remove "Alternative" and add in its place "Alternative Filtration".

§ 141.563 [Amended]

■ 21. Section 141.563 is amended as follows:
■ a. In paragraph (b) remove the last sentence in the second column of the table, and

■ b. In paragraph (c) remove "BTU" and add in its place "NTU" in the first column of the table.

■ 22. In § 141.570, revise paragraph (b)(2) in the table to read as follows:

§ 141.570 What does subpart T require that my system report to the State?

* * * * *

Corresponding requirement	Description of information to report	Frequency
* *	* * *	* *
(b) Individual Filter Turbidity Requirements (§§ 141.560–141.564).	(2) The filter number(s), corresponding date(s), and the turbidity value(s) which exceeded 1.0 NTU during the month, and the cause (if known) for the exceedance(s), but only if 2 consecutive measurements exceeded 1.0 NTU.	By the 10th of the following month.
* *	* * *	* *

PART 142—NATIONAL PRIMARY DRINKING WATER REGULATIONS IMPLEMENTATION

■ 23. The authority citation for part 142 continues to read as follows:

Authority: 42 U.S.C. 300f, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–4, 300j–9, and 300j–11.

§ 142.14 [Amended]

■ 24. Section § 142.14 is amended as follows:

■ a. In paragraph (d)(12)(iv) remove the citation "§ 142.16(f)(2)" and add in its place "§ 142.16(h)(2)"; and

■ b. In paragraph (d)(13) remove the citation "§ 142.16(f)(5)" and add in its place "§ 142.16(h)(5)".

§ 142.16 [Amended]

■ 25. Section 142.16 is amended as follows:

■ a. In paragraph (l)(2) remove the citation "§ 142.16(e)(5)"and add in its place "§ 142.16(e)(2)";

■ b. Add and reserve paragraphs (m), (n), and (o);

■ c. Redesignate paragraph (j) which was added on January 14, 2002, at 67 FR 1812 as paragraph (p); and

■ d. In newly designated paragraph (p)(2)(ii) remove the citation "141.536" and add in its place "141.535".

§ 142.62 [Amended]

■ 26. Section 142.62(g)(2) is amended by removing the citation "103.35" and add in its place "165.110".

[FR Doc. 04–14604 Filed 6–28–04; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 660

[Docket No. 031216314–3314–01; I.D. 062304A]

Fisheries Off West Coast States and in the Western Pacific; Pacific Coast Groundfish Fishery; Annual Specifications and Management Measures; Inseason Adjustments

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

ACTION: Inseason adjustments to management measures; request for comments.

SUMMARY: NMFS announces changes to the commercial limited entry fixed gear primary season sablefish tier limits for the Pacific Coast groundfish fishery. These actions, which are authorized by the Pacific Coast Groundfish Fishery Management Plan (FMP), will allow fisheries to access more abundant groundfish stocks while protecting overfished and depleted stocks.

DATES: Effective 0001 hours (local time) June 29, 2004, until the 2005–06 annual specifications and management measures are effective; unless modified, superseded, or rescinded through a publication in the **Federal Register**. Comments on this rule will be accepted through July 28, 2004.

ADDRESSES: You may submit comments, identified by (I.D. 062304A), by any of the following methods:

- E-mail: *GroundfishInseason#4.nwr@noaa.gov*: Include the I.D. number in the subject line of the message.
- Federal eRulemaking Portal: *http://www.regulations.gov*. Follow the instructions for submitting comments.
- Mail: D. Robert Lohn, Administrator, Northwest Region, NMFS, 7600 Sand Point Way NE, Seattle, WA 98115–0070; or Rod McInnis, Acting Administrator, Southwest Region, NMFS, 501 West Ocean Blvd, Suite 4200, Long Beach, CA 90802–4213.
- Fax: 206–526–6736

FOR FURTHER INFORMATION CONTACT: Jamie Goen (Northwest Region, NMFS), phone: 206–526–6150; fax: 206–526–6736; and e-mail: *jamie.goen@noaa.gov*.

SUPPLEMENTARY INFORMATION:

Electronic Access

This **Federal Register** document is available on the Government Printing Office's website at: *www.gpoaccess.gov/fr/index.html*.

Background information and documents are available at the NMFS Northwest Region website at: *www.nwr.noaa.gov/1sustfsh/gdfsh01.htm* and at the Pacific Fishery Management Council's website at: *www.pcouncil.org*.

Background

The Pacific Coast Groundfish FMP and its implementing regulations at 50 CFR part 660, subpart G, regulate fishing for over 80 species of groundfish off the coasts of Washington, Oregon, and California. Groundfish specifications and management measures are developed by the Pacific Fishery Management Council (Pacific Council), and are implemented by NMFS. The specifications and management measures for the 2004 fishing year (January 1 - December 31, 2004) were initially published in the **Federal Register** as an emergency rule for January 1 - February 29, 2004 (69 FR 1322, January 8, 2004), and as a proposed rule for March 1 - December 31, 2004 (69 FR 1380, January 8, 2004). The emergency rule was amended at 69 FR 4084, January 28, 2004, and the final rule for March 1 - December 31, 2004, was published in the **Federal Register** on March 9, 2004 (69 FR 11064), and subsequently amended at 69 FR 23440 (April 29, 2004), 69 FR 23667 (April 30, 2004), 69 FR 25013 (May 5, 2004)and 69 FR 28086 (May 18, 2004).

The following changes to current groundfish management measures were recommended by the Pacific Council, in consultation with Pacific Coast Treaty Indian Tribes and the states of Washington, Oregon, and California, at its June 14–18, 2004, meeting in Foster City, CA. Pacific Coast groundfish landings will be monitored throughout the year, and further adjustments to trip limits or management measures will be made as necessary to allow achievement of, or to avoid exceeding the 2004 optimum yields (OYs).

Limited Entry Fixed Gear Primary Sablefish Fishery

NMFS made an error in calculating the limited entry fixed gear primary sablefish fishery tier limits for the 2004 season. Initially, the 2003 tier limits were used as a placeholder for the 2004 primary season in the final rule (69 FR 11064, March 9, 2004) until the new observer data was released in the spring of 2004. Bycatch rates from the new observer data were used to update the model which calculates the sablefish tier limits. The 2004 tier limits were expected to be higher than the 2003 limits based on the new, lower bycatch rates and the higher sablefish OY for 2004. Updated, higher tier limits for 2004 were published in the **Federal Register** on May 5, 2004 (69 FR 25013) after the start of the primary sablefish season. Subsequently, NMFS discovered an error in its calculation of the 2004 tier limits. The tier limits were calculated from the 2004 sablefish acceptable biological catch (ABC) rather than from the OY. Thus, the 2004 tier limits were substantially higher than they should have been and, if fully harvested, may result in allowing the fisheries to exceed the sablefish OY by approximately 172 mt (78 kg), which is 2 percent of the total 2004 sablefish OY. The primary sablefish season started on April 1 and tier limits through April in PacFIN show landings are tracking slower this year than last year. However, due to the delay in reported landings data into PacFIN, it is likely that more of the higher, erroneous tier limits have already been landed. NMFS estimates that between 50 and 75 percent of the sablefish tier limits may have already been landed at the higher, erroneous tier limits. Based on those percentages, and assuming the same tier limit tonnage that was not landed in 2003 will remain unlanded in 2004, the primary sablefish fishery may be 40 to 83 mt over the amount originally planned for that fishery. Presumably, additional tonnage will remain unharvested from the limited entry fixed gear and open access daily trip limit fisheries and total harvest will remain below the sablefish OY. With the delay in landings reported into PacFIN from fish tickets, along with the uncertainty on how many fishermen are actively fishing their tiers, it is difficult to determine at this time if the sablefish OY will be exceeded in 2004. NMFS will continue to track landings in this fishery, and if landings are tracking high and approaching the sablefish OY, NMFS will consult with the Pacific Council at its September 12 - 17, 2004, meeting to determine what further adjustments may be necessary in this fishery.

The Pacific Council recommended, and NMFS is implementing, reductions in the primary season sablefish tier limits as follows: Tier 1 will be reduced from 69,600 lb (31,570 kg) to 64,300 lb (29,166 kg), Tier 2 will be reduced from 31,600 lb (14,334 kg) to 29,200 lb (13,245 kg), and Tier 3 will be reduced from 18,100 lb (8,210 kg) to 16,700 lb (7,575 kg). These are the limits that should have been set in place in May, had they been calculated from the sablefish OY instead of the ABC.

A permit holder who has already landed his or her tier limits is not in violation of these regulations if the holder was complying with the regulations in effect at the time of landing. For permit holders who at this time have only partially achieved their tier limits, any past catch during the 2004 primary season will count toward the adjusted, lower tier limit. For example, a stacked Tier 1 and Tier 2 permit would have previously had a cumulative limit of 101,200 lb (45,904 kg) and now has a cumulative limit of 93,500 lb (42,411 kg). If 70,000 lb (31,752 kg) have already been landed on a stacked Tier 1 and Tier 2 permit prior to this inseason action, 23,500 lb (10,659 kg) would remain to be fished on those stacked permits.

NMFS Actions

For the reasons stated herein, NMFS concurs with the Pacific Council's recommendations and hereby announces the following changes to the 2004 specifications and management measures (69 FR 11064, March 9, 2004), as subsequently amended at 69 FR 23440 (April 29, 2004), 69 FR 23667 (April 30, 2004), 69 FR 25013 (May 5, 2004)and 69 FR 28086 (May 18, 2004), to read as follows:

1. In section IV., under B. Limited Entry Fishery, paragraph (2)(b)(i) is revised to read as follows:

* * * * *

B. Limited Entry Fishery

(2) * * *

(b) * * *

(i) *Primary season*. The primary season begins at 12 noon l.t. on April 1, 2004, and ends at 12 noon l.t. on October 31, 2004. There are no pre-season or post-season closures. During the primary season, each vessel with at least one limited entry permit with a sablefish endorsement that is registered for use with that vessel may land up to the cumulative trip limit for each of the sablefish-endorsed limited entry permits registered for use with that vessel, for the tier(s) to which the permit(s) are assigned. For 2004, the following limits are in effect: Tier 1, 64,300 lb (29,166 kg); Tier 2, 29,200 lb (13,245 kg); and Tier 3, 16,700 lb (7,575 kg). All limits are in round weight. If a vessel is registered for use with a sablefish-endorsed limited entry permit, all sablefish taken after April 1, 2004, count against the cumulative limits associated with the permit(s) registered for use with that vessel.

* * * * *

Classification

These actions are authorized by the Pacific Coast groundfish FMP and its implementing regulations, and are based on the most recent data available. The aggregate data upon which these actions are based are available for public inspection at the Office of the Administrator, Northwest Region, NMFS, (see **ADDRESSES**) during business hours.

The Assistant Administrator for Fisheries, NOAA, finds good cause to waive the requirement to provide prior notice and opportunity for public comment on this action pursuant to 5 U.S.C. 553(b)(3)(B), because providing prior notice and opportunity for comment would be impracticable. Providing prior notice and comment on the inseason adjustment would be impracticable because the data upon which these recommendations were based was provided to the Pacific Council and the Pacific Council made its recommendations at its June 14–18, 2004, meeting in Foster City, CA. There was not sufficient time after that meeting to draft this notice and undergo proposed and final rulemaking before these actions need to be in effect as explained below. The adjustments to management measures in this document are changes to the limited entry primary sablefish fishery tier limits. Changes are being made to correct an error in the calculation of the sablefish tier limits. The tier limits implemented on May 1, 2004 were incorrectly calculated using the sablefish ABC rather than the OY. Thus, tier limits were higher than they should have been. Leaving these in place would result in allowing fisheries to exceed the sablefish OY if all tier limits were achieved. The sablefish tier limits in this inseason action are recalculated using the sablefish OY to reduce the take of sablefish in an effort to keep harvest within the OY set for the year. Delaying these changes to management measures could lead to early closures of the fishery. This would contradict one of the Pacific Coast Groundfish FMP objectives of providing for year-round harvest opportunities or extending fishing opportunities as long as practicable during the fishing year. Alternatively, delay could lead to exceeding the OY. Finally, providing prior notice and public comment would provide most permit holders an opportunity to take their higher tier limits before the effective date of this notice, which would negate any benefit from this notice. As explained above, prior notice and opportunity for comment would be impracticable because affording prior notice and opportunity for public comment would take too long, thus impeding the Agency's function of managing fisheries to approach without exceeding the OYs for federally managed species.

For these reasons, good cause also exists to waive the 30 day delay in effectiveness requirement under 5 U.S.C. 553 (d)(3).

These actions are taken under the authority of 50 CFR 660.323(b)(1) and are exempt from review under Executive Order 12866.

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

Dated: June 23, 2004.

Alan D. Risenhoover,

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

[FR Doc. 04–14717 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–22–S

Proposed Rules

Federal Register
Vol. 69, No. 124
Tuesday, June 29, 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

[MD135–3099b; FRL–7671–3]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Control of Volatile Organic Compound Emissions From Portable Fuel Containers

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA proposes to approve the State Implementation Plan (SIP) revision submitted by the State of Maryland for the purpose of establishing Volatile Organic Compound (VOC) emission standards for portable fuel containers. In the Final Rules section of this **Federal Register**, EPA is approving the State's SIP submittal as a direct final rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no adverse comments are received in response to this action, no further activity is contemplated. If EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed rule. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time.

DATES: Comments must be received in writing by July 29, 2004.

ADDRESSES: Submit your comments, identified by MD 135–3099 by one of the following methods:

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

B. *E-mail: morris.makeba@epa.gov*

C. *Mail:* Makeba Morris, Chief, Air Quality Planning Branch, Mailcode 3AP21, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103.

D. *Hand Delivery:* At the previously-listed EPA Region III address. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. MD 135–3099. EPA's policy is that all comments received will be included in the public docket without change, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through regulations.gov or e-mail. The Federal regulations.gov Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Copies of the documents relevant to this action are available for public inspection during normal business hours at the Air Protection Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103; and the Maryland Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland, 21230.

FOR FURTHER INFORMATION CONTACT: Marilyn Powers, (215) 814–2308, or by e-mail at *powers.marilyn@epa.gov.*

SUPPLEMENTARY INFORMATION: For further information, please see the information provided in the direct final action, with the same title, that is located in the "Rules and Regulations" section of this Federal Register publication.

Dated: May 27, 2004.

James W. Newsom,

Acting Regional Administrator, Region III.

[FR Doc. 04–14603 Filed 6–28–04; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 579

[Docket No. NHTSA 2001–8677; Notice 10]

RIN 2127–AJ41

Reporting of Information and Documents About Potential Defects

AGENCY: National Highway Traffic Safety Administration (NHTSA), DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This document proposes to amend the date by which quarterly early warning reports are to be submitted to the agency from 30 days following the end of a calendar quarter to 60 days following the end of a calendar quarter. This also proposes to amend the date by which copies of non-dealer field reports are to be submitted from 30 days after the quarterly reports are due to 15 days after those reports are due.

DATES: Comments Closing Date: Comments must be received on or before July 29, 2004.

ADDRESSES: You may submit comments identified by DOT DMS Docket Number NHTSA 2004–8677 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 20590–0001.
- Hand Delivery: Room PL–401 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 am and 5 pm, Monday

through Friday, except Federal Holidays.

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

Instructions: All submissions must include the agency name and docket number or Regulatory Identification Number (RIN) for this rulemaking. For detailed instructions on submitting comments and additional information on the rulemaking process, see the Request for Comments 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 of the **SUPPLEMENTARY INFORMATION** section of this document regarding documents submitted to the agency's dockets.

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 Federal Holidays.

FOR FURTHER INFORMATION CONTACT: For non-legal issues, contact Jonathan White, Office of Defects Investigation, NHTSA (phone: 202–366–5226). For legal issues, contact Andrew DiMarsico, Office of Chief Counsel, NHTSA (phone: 202–366–5263).

You may send mail to these officials at National Highway Traffic Safety Administration, 400 Seventh Street, SW., Washington, DC 20590.

SUPPLEMENTARY INFORMATION:

I. Background

On July 10, 2002, NHTSA published a final rule implementing the early warning reporting (EWR) provisions of the Transportation Recall Enhancement, Accountability, and Documentation (TREAD) Act. 49 U.S.C. 30166(m) (67 FR 45822). The final rule established a schedule for the reporting of information and submission of copies of certain field reports required by the rule. The first calendar quarter for which reports were required was the second calendar quarter of 2003. See 49 CFR 579.28(a)(2002). For the quarterly reporting periods in 2003, the reports were due within 60 days after the end of the quarter. Thereafter, starting in 2004, reports were to be due within 30 days after the end of the quarter. See 49 CFR 579.28(b) (2002).

In response to a petition for reconsideration of the final rule, on June 11, 2003, NHTSA amended the reporting dates. Under the revised rule, the initial reporting period for all quarterly data [1] other than historical reports and copies of non-dealer field reports, was the third quarter of 2003. Reports covering the last two quarters of 2003 and the first quarter of 2004 were due to NHTSA within 60 days after the close of the reporting period. Thereafter, reports currently are due within 30 days after the close of the quarter. NHTSA also amended the requirements for submission of copies of non-dealer field reports. The initial reporting period for the submission of copies of non-dealer field reports was the first calendar quarter of 2004. The field reports currently are due within 30 days after the quarterly data are due. 49 CFR 579.28(b), (n) (2003); *see* 68 FR 35145 (June 11, 2003).

II. Petition for Extension of Time to Submit EWR Data.

On April 22, 2004, the Alliance of Automobile Manufacturers (Alliance) petitioned NHTSA to conduct a rulemaking to allow manufacturers to submit EWR quarterly reports within 60 days after the close of the quarterly reporting period, rather than the 30 days allowed in the current regulation, beginning with the report for the second calendar quarter of 2004. The Alliance stated that vehicle manufacturers have learned through the experience of the first three reporting periods that the processing and reporting of early warning information will take longer than 30 days. As a result, the Alliance stated, despite the manufacturers' best efforts, if the reports were due 30 days after the end of the quarter a significant amount of reportable data could inadvertently be excluded from the reports, and included in the following quarter's reports instead. In order to avoid such incomplete reporting, the Alliance requests an additional 30 days to provide the quarterly data.

III. Discussion

When we issued the final rule, and when we postponed the initial reporting period on reconsideration, we believed that after manufacturers had three opportunities to gain experience in making EWR submissions, 30 days after the end of each calendar quarter would be a sufficient amount of time for submitting EWR information. However, on the basis of the Alliance's petition and our experience in receiving EWR data, we are proposing to revise section 579.28(b) to permit manufacturers to submit EWR quarterly data not later than 60 days after the end of each calendar quarter.

The EWR rule requires manufacturers to submit large amounts of data that are stored in a variety of locations. As manufacturers have compiled and reported EWR information, they have gained a better understanding of the amount of time it takes them to collect, collate and report the information. Based upon the experience of the Alliance's members, it appears that at least for the foreseeable future, manufacturers need more than 30 days to provide complete and accurate EWR reports to NHTSA. Incomplete or inaccurate data would not serve NHTSA well. Complete quarterly reports are far more useful in comparing various data to determine whether there are trends that are indicative of a potential defect. In fact, incomplete reports could lead the agency to fail to notice potential defects or to examine issues unnecessarily.

As we have stated in earlier **Federal Register** notices on the early warning reporting program, we plan to review the EWR regulation after two years of experience. During the course of this review, we will assess whether the appropriate time for quarterly reporting should be 30, 60 or some other number of days after the end of the reporting period.

Under the current regulations, copies of non-dealer field reports are due to NHTSA within 30 days after the other quarterly reports are due. 49 CFR 579.28(n). In essence, beginning with the second quarter of 2004, these reports are now due 60 days after the end of the quarter. Given the structure of the regulation, which bases the due date for non-dealer field reports on the due date for quarterly reports, if we were to change the due date for the quarterly reports and make no other changes, the non-dealer field reports would be due 90 days after the end of the quarter. We do not see any need for such a delay, which could delay our ability to identify potential safety defects. However, to avoid any possibility that the submission of the field reports could interfere with the submission of the quarterly data, we want to continue to stagger the two dates. We believe that a difference of 15 days is sufficient for this purpose. Therefore, we propose to change the language of subsection 579.28(n) to require non-dealer field reports to be submitted not later than 15 days after the quarterly data is due,

[1] In general, quarterly reports include information on production, incidents involving death or injury, numbers of property damage claims, numbers of consumer complaints, numbers of warranty claims or warranty adjustments, and numbers of field reports. See *e.g.*, 49 CFR 579.21.

which would be 75 days after the end of the calendar quarter.

IV. Request for Comments

How Do I Prepare and Submit Comments?

Your comments must be written and in English. To ensure that your comments are correctly filed in the Docket, please include the docket number of this document in your comments.

Your comments must not be more than 15 pages long (49 CFR 553.21). We established this limit to encourage you to write your primary comments in a concise fashion. However, you may attach necessary additional documents to your comments. There is no limit on the length of the attachments.

Please submit two copies of your comments, including the attachments, to Docket Management at the beginning of this document, under **ADDRESSES**. You may also submit your comments electronically to the docket following the steps outlined under **ADDRESSES**.

How Can I Be Sure That My Comments Were Received?

If you wish Docket Management to notify you upon its receipt of your comments, enclose a self-addressed, stamped postcard in the envelope containing your comments. Upon receiving your comments, Docket Management will return the postcard by mail.

How Do I Submit Confidential Business Information?

If you wish to submit any information under a claim of confidentiality, you should submit the following to the Chief Counsel (NCC–110) at the address given at the beginning of this document under the heading **FOR FURTHER INFORMATION CONTACT:** (1) A complete copy of the submission; (2) a redacted copy of the submission with the confidential information removed; and (3) either a second complete copy or those portions of the submission containing the material for which confidential treatment is claimed and any additional information that you deem important to the Chief Counsel's consideration of your confidentiality claim. A request for confidential treatment that complies with 49 CFR part 512 must accompany the complete submission provided to the Chief Counsel. For further information, submitters who plan to request confidential treatment for any portion of their submissions are advised to review 49 CFR part 512, particularly those sections relating to document submission requirements. Failure to adhere to the requirements of part 512 may result in the release of confidential information to the public docket. In addition, you should submit two copies from which you have deleted the claimed confidential business information, to Docket Management at the address given at the beginning of this document under **ADDRESSES**.

Will the Agency Consider Late Comments?

We will consider all comments that Docket Management receives before the close of business on the comment closing date indicated at the beginning of this notice under DATES. In accordance with our policies, to the extent possible, we will also consider comments that Docket Management receives after the specified comment closing date. If Docket Management receives a comment too late for us to consider in developing the proposed rule, we will consider that comment as an informal suggestion for future rulemaking action.

How Can I Read the Comments Submitted by Other People?

You may read the comments received by Docket Management at the address and times given near the beginning of this document under **ADDRESSES**.

You may also see the comments on the Internet. To read the comments on the Internet, take the following steps:

(1) Go to the Docket Management System (DMS) Web page of the Department of Transportation (*http://dms.dot.gov/*).

(2) On that page, click on "search."

(3) On the next page (*http://dms.dot.gov/search/*), type in the four-digit docket number shown at the heading of this document. Example: if the docket number were "NHTSA–2001–1234," you would type "1234."

(4) After typing the docket number, click on "search."

(5) The next page contains docket summary information for the docket you selected. Click on the comments you wish to see.

You may download the comments. The comments are imaged documents, in either TIFF or PDF format. Please note that even after the comment closing date, we will continue to file relevant information in the Docket as it becomes available. Further, some people may submit late comments. Accordingly, we recommend that you periodically search the Docket for new material.

V. Privacy Act Statement

Anyone is able to search the electronic form of all comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477) or you may visit *http://dms.dot.gov.*

VI. Rulemaking Analyses

Regulatory Policies and Procedures. Executive Order 12866, "Regulatory Planning and Review" (58 FR 51735, October 4, 1993) provides for making determinations whether a regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and to the requirements of the Executive Order. The Order defines as "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.

This document was not reviewed under E.O. 12866 or the Department of Transportation's regulatory policies and procedures. This rulemaking action is not significant under Department of Transportation policies and procedures. The impacts of this rule are expected to be so minimal as not to warrant preparation of a full regulatory evaluation because this proposal would only revise the time period for reporting certain EWR data from 30 days to 60 days after the calendar quarter ends and revise the date for submission of certain field reports by 15 days. This document does not otherwise change the substance of the reports.

Regulatory Flexibility Act. The Regulatory Flexibility Act of 1980 (5 U.S.C. 601 *et seq.*) requires agencies to evaluate the potential effects of their proposed and final rules on small businesses, small organizations and small governmental jurisdictions. This was addressed in the final rule and a response to petitions for reconsideration. *See* 67 FR 45870–71 and 69 FR 3292, 3297 respectively. Today's proposal simply extends dates for reporting information under the EWR rule and does not impose any new burdens on small businesses. Based on the analyses performed in the final rule (67 FR 45870–71) and the response to petitions for rulemaking (69 FR 3292, 3297), I certify that this proposed rule will not have a significant economic impact on a substantial number of small entities.

Executive Order 13132 (Federalism). Executive Order 13132 on "Federalism" requires us 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." The Executive Order defines this phrase 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 agency has analyzed this proposed rule in accordance with the principles and criteria set forth in Executive Order 13132 and has determined that it will not have sufficient federalism implications to warrant consultation with State and local officials or the preparation of a federalism summary impact statement. This changes proposed in this document only affect a rule that regulates the manufacturers of motor vehicles and motor vehicle equipment, which does not have 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, as specified in Executive Order 13132.

Civil Justice Reform. This proposed rule will not have a retroactive or preemptive effect, and judicial review of it may be obtained pursuant to 5 U.S.C. 702. That section does not require that a petition for reconsideration be filed prior to seeking judicial review.

Paperwork Reduction Act. Today's proposal simply extends the reporting period for the submission of EWR data. The proposal does not create new information collection requirements, as that term is defined by the Office of Management and Budget (OMB) in 5 CFR Part 1320. To the extent that this proposed rule implicates the Paperwork Reduction Act, we will rely upon our previous clearance from OMB. To obtain a three-year clearance for information collection for the EWR rule, we published a Paperwork Reduction Act notice on June 25, 2002 (67 FR 42843) pursuant to the requirements of that Act (44 U.S.C. 3501 *et seq.*). We received clearance from OMB on December 20, 2002, which will expire on December 31, 2005. The clearance number is 2127–0616. The amendments proposed by this document do not change the overall paperwork burden. They simply extend the dates for reporting certain information pursuant to the EWR rule.

Data Quality Act Section 515 of the FY 2001 Treasury and General Government Appropriations Act (Pub. L. 106–554, section 515, codified at 44 U.S.C. 3516 historical and statutory note), commonly referred to as the Data Quality Act, directed OMB to establish government-wide standards in the form of guidelines designed to maximize the "quality," "objectivity," "utility," and "integrity" of information that Federal agencies disseminate to the public. As noted in the EWR final rule (67 FR 45822), NHTSA has reviewed its data collection, generation, and dissemination processes in order to ensure that agency information meets the standards articulated in the OMB and DOT guidelines. The changes proposed by today's document simply extends the reporting period for submission of data pursuant to the EWR rule and do not have any effects on data quality.

Unfunded Mandates Reform Act. The Unfunded Mandates Reform Act of 1995 (Public Law 104–4) requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in expenditures by State, local or tribal governments, in the aggregate, or by the private sector, of more than $100 million annually (adjusted annually for inflation with base year of 1995). The final rule did not have unfunded mandates implications. 67 FR 49263 (July 30, 2002). Today's proposal simply extends the reporting period for submission of data pursuant to the EWR rule and does not create any unfunded mandates within the meaning of this Act.

List of Subjects in 49 CFR Part 579

Imports, Motor vehicle safety, Motor vehicles, Reporting and recordkeeping requirements.

In consideration of the foregoing, 49 CFR chapter V is amended as follows:

PART 579—REPORTING OF INFORMATION AND COMMUNICATIONS ABOUT POTENTIAL DEFECTS

1. The authority citation for part 579 continues to read as follows: Sec. 3, Pub. L. 106–414, 114 Stat. 1800 (49 U.S.C. 30102–103, 30112, 30117–121, 30166–167); delegation of authority at 49 CFR 1.50.

Subpart C—Reporting of Early Warning Information

2. In § 579.28, revise paragraphs (b) and (n) to read as follows:

§ 579.28 Due date of reports and other miscellaneous provisions.

* * * * *

(b) *Due date of reports.* Except as provided in paragraph (n) of this section, each manufacturer of motor vehicles and motor vehicle equipment shall submit each report that is required by this subpart not later than 60 days after the last day of the reporting period.

* * * * *

(n) *Submission of copies of field reports.* Copies of field reports required under this subpart shall be submitted not later than 15 days after reports are due pursuant to paragraph (b) of this section.

Issued on: June 24, 2004.

Kenneth N. Weinstein,

Associate Administrator for Enforcement.

[FR Doc. 04–14699 Filed 6–24–04; 3:58 pm]

BILLING CODE 4910–59–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

RIN 1018–AT54

Endangered and Threatened Wildlife and Plants; Special Rule To Control the Trade of Threatened Beluga Sturgeon (*Huso huso*)

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), are proposing to establish a special rule under Section 4(d) of the Endangered Species Act of 1973, as amended (Act), to exempt the international, foreign, and interstate commerce in certain beluga sturgeon (*Huso huso*) products from threatened species permits normally required under 50 CFR 17.32. Beluga sturgeon occur in the Caspian and Black Seas, and are found in the territorial waters of 11 countries (*i.e.*, the range countries). Over-harvest, severe habitat degradation, and other factors have led to the listing of beluga sturgeon as threatened throughout its range under the Act and in Appendix II of the

Convention on International Trade in Endangered Species of Wild Fauna and Flora (CITES). In our final listing rule, we delayed the effective date of the threatened listing for 6 months in order to promulgate a 4(d) rule. After the listing becomes effective, the Act will prohibit all trade (foreign, international, and interstate) in beluga sturgeon and beluga sturgeon products, except as provided in the special rule or with permits under the provision of Section 10 of the Act. This proposed special rule initially allows range countries 6 months from the rule's effective date to submit a suite of reports and management measures to us for review. During this initial waiting period, imports, re-exports, and interstate and foreign commerce of certain beluga sturgeon products will continue without a requirement for threatened species permits. This is intended to provide the range countries time to submit the required documents. CITES documentation will still be required.

Under this proposed rule, beluga caviar and beluga sturgeon meat originating from wild-caught fish or range country hatcheries may be transferred into and out of the United States without threatened species permits. We will also exempt interstate and foreign commerce in these products from permit requirements, if that trade occurs in the United States or involves U.S. citizens. However, after an initial 6 months of information gathering in the range states, these exemptions will occur only after the range countries have fulfilled certain requirements as described below. In addition, all relevant provisions of CITES will continue to govern the international trade in all beluga sturgeon products. We are proposing to allow this conditional trade to promote effective conservation of *Huso huso* in the range countries, through demonstrable law enforcement and cooperative management activities.

DATES: Comments must be received by July 29, 2004. Public hearing requests must be received by July 14, 2004.

ADDRESSES: Submit any comments, information, and questions by mail to the Chief, Division of Scientific Authority, U.S. Fish and Wildlife Service, 4401 N. Fairfax Drive, Room 750, Arlington, Virginia 22203, or by fax, 703–358–2276, or by e-mail, *Scientificauthority@fws.gov*. Comments and supporting information will be available for public inspection, by appointment, from 8 a.m. to 4 p.m. at the above address.

FOR FURTHER INFORMATION CONTACT: John Field at the above address, or by phone, 703–358–1708; fax, 703–358–2276; or e-mail, *Scientificauthority@fws.gov*.

SUPPLEMENTARY INFORMATION:

Background

On April 21, 2004, the Service published a final rule (69 FR 21425) to list beluga sturgeon, *Huso huso*, as threatened throughout its range under the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*). That listing in 50 CFR 17.11 will prohibit all trade (foreign, international, and interstate) in beluga sturgeon, except as provided in this special rule. We delayed the effective date of the listing until October 21, 2004, in order to gather public comments on this special rule, allow adequate time to address those comments, and promulgate a final special rule.

The beluga sturgeon is a large fish from which highly valued beluga caviar is obtained. The species' range was reduced during the 20th century, and is now limited to the Caspian and Black Sea basins, which comprise the territorial waters of 11 countries (Azerbaijan, Bulgaria, Georgia, Iran, Kazakhstan, Moldova, Romania, Russia, Turkey, Turkmenistan, and Ukraine). Hereafter the term "Black Sea" describes both the Black Sea and Sea of Azov basins, which are connected via the Kerch Strait. The species is threatened by habitat modification and degradation, over-exploitation for trade, and limited natural reproduction. The species has benefited from a number of positive conservation measures for all Acipenseriformes species (sturgeons and paddlefishes), which are listed in Appendices I (2 species of sturgeons) and II (23 species of sturgeons and paddlefishes) of CITES. Although commercial trade in Appendix-I species is prohibited, CITES Appendix-II species (such as beluga sturgeon) may be traded commercially under a system of permits and international cooperation by the importing and exporting countries.

Over the last several years, the CITES Parties that harvest and trade in sturgeons and sturgeon products (especially caviar) have been compelled by other CITES Parties to commit to cooperative quota setting, better trade controls, and new management systems to help ensure the species' conservation. We believe that conservation measures for Caspian Sea and Black Sea sturgeon species (like beluga sturgeon) that have been required by the CITES Standing Committee could be effective if fully implemented and expanded upon. We also believe that the most effective way to motivate range countries to implement these measures is to allow continued open access to U.S. commercial markets (currently responsible for 80 percent of beluga caviar trade) while requiring specific improvements in regional and national management programs for the species. Therefore, we are proposing this special rule, as permitted under Section 4(d) of the Act, to permit continued commercial importation of certain beluga sturgeon products subject to specific provisions. We believe this special rule is necessary and advisable for the species' conservation because it: (a) Offers the greatest incentive for range countries to remain engaged with the United States in *Huso huso* recovery and conservation; (b) exceeds the requirements of CITES for data reporting, management planning, and research transparency; and (c) will continue to impose requirements on the range countries after they satisfy current CITES stipulations.

Description of the Special Rule

The purpose of this proposed special rule is to enhance conservation of wild beluga sturgeon by requiring properly designed and implemented fishery management programs in the range countries. We believe that the greatest benefit for the conservation of beluga sturgeon will be attained through continued involvement with range countries that have access to our commercial sturgeon markets, and by conditioning this access on proper management and recovery of wild populations in their waters. The alternative to this special rule is to strictly prohibit U.S. trade in beluga sturgeon products, except as permitted under Section 10 of the Act. We believe this alternative is less advisable than the special rule for a number of reasons, as described at the end of the section entitled "Effects of the Special Rule." We intend to use this special rule to build upon the progress already made by the range countries in CITES forums, while recognizing that there are certain data gaps and information and management needs yet to be filled.

For example, we note that since 2001 the range countries in the Black Sea and Caspian Sea basins have committed to cooperative management frameworks, including the Black Sea Sturgeon Management Group and the Commission on Aquatic Bioresources of the Caspian Sea.

These bodies have set annual quotas for beluga and other sturgeon species in the two basins, and have representatives from each of the sturgeon-harvesting and -trading range countries in the respective regions. Despite the progress made by the range countries, we concur with findings of recent reports from the CITES Secretariat (Anonymous, 2002a; 2002b) on problems in national and regional *Huso huso* management. These include: (a) The absence of a formal, written management plan for Caspian Sea and Black Sea beluga sturgeon as called for in CITES Resolution Conf. 12.7 and Decision 12.50; (b) a lack of transparency in data analysis and quota setting; (c) continued high levels of poaching and illegal trade; and (d) a data-poor evaluation of hatchery protocols and restocking programs. Therefore, for those range countries wishing to export beluga sturgeon caviar and meat to the United States, this special rule would require:

1. Submission of basin-wide beluga sturgeon management plans for the Black Sea and Caspian Sea range countries;
2. Submission of national regulations that implement the basin-wide cooperative plan mentioned in item 1, including information on hatchery and restocking protocols and monitoring results;
3. Submission of annual reports documenting management measures in place and current status of *Huso huso* in the given country;
4. Labeling of exported, re-exported, and domestically traded beluga caviar products as per CITES Resolutions and Decisions;
5. Biennial review by the Service of range country management and restocking programs for beluga sturgeon;
6. Compliance with CITES provisions and recommendations (including permits) for beluga sturgeon imports into the United States; and
7. Suspension of imports basin-wide or by country if the conservation status or management approach for *Huso huso* changes and compromises the recovery of beluga sturgeon in the wild. See discussion below for how such a suspension would be imposed.

The trade in caviar and meat taken from wild or hatchery-origin beluga sturgeon and originating from the range countries would be exempt from threatened species permits under this special rule. The current range countries are Azerbaijan, Bulgaria, Georgia, Iran, Kazakhstan, Moldova, Romania, Russia, Turkey, Turkmenistan, and Ukraine. For the purposes of this special rule, "beluga caviar" refers to processed unfertilized eggs from female *Huso huso* intended for human consumption. "Beluga meat" refers to excised muscle tissue of *Huso huso* destined for human consumption.

This special rule would not exempt from threatened species permit requirements the international trade in live specimens of beluga sturgeon, including adults, gametes (eggs or sperm), fingerlings, and viable eggs. It would not exempt beluga sturgeon or any beluga products derived from aquaculture or grow-out operations outside the range countries from the provisions of the Act, which we believe could undermine the economic incentives for sustainable harvests of wild *Huso huso* in the range countries. Furthermore, non-range country aquaculture of the species, if exempted from provisions of the Act under this special rule, could utilize Huso huso broodstock from the range countries without any direct benefit to wild populations. We also believe that aquaculture or grow-out of foreign sturgeon species in the United States poses a risk to the recovery efforts for several native sturgeon species listed under the Act or under interstate recovery plans. This risk comes from the potential competition between native sturgeons and unintentionally released fish from facilities culturing foreign sturgeon and disease transmission from foreign species (ASMFC, 1998; NMFS, 1998; USFWS and GSMFC, 1995). Therefore, import, export, re-export, or interstate or foreign commerce involving any beluga sturgeon products that originate from aquaculture operations outside the range countries would still require a threatened species permit in addition to any applicable CITES documents (except as provided for captive-bred wildlife in 50 CFR 17.21(g)).

As per CITES Resolution Conf. 12.9, and existing U.S. policy, this special rule would allow for the legal importation of personal effects of caviar. Under Resolution Conf. 12.9, individuals may import up to 250 grams of any Appendix-II Acipenseriformes caviar without a CITES permit. This allowance would apply in the United States, and importation of personal effects of beluga caviar (as defined by the CITES Parties) would not require a threatened species permit under the Act, if the proposed rule is adopted. However, any trade suspension administratively implemented under this special rule would also prohibit the importation of beluga caviar personal effects.

Under the proposed rule we will require the submission of certain documentation from the range countries, specifically:

1. Within 6 months of the effective date of this special rule, if adopted, range countries wishing to export beluga caviar and meat to the United States must submit a written, basin-wide management plan that addresses *Huso huso* conservation. This plan must be agreed to by each country within the range of beluga sturgeon in the relevant basin (not just exporting nations). Presently, these include Bulgaria, Georgia, Moldova, Romania, Turkey, and Ukraine in the Black Sea and Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan in the Caspian Sea. This basin-wide management plan must contain the following elements:

a. A clear statement of the recovery and management objectives for the plan, including a specification of the stock(s) concerned, a definition of what constitutes over-fishing for that stock, and a rebuilding objective and schedule for that stock;

b. A statement of standard management strategies to be utilized by the nations involved (*e.g.*, size limits, target harvest rates, quotas, seasons, fishing gear, or effort caps);

c. A complete statement of the specific regulatory, monitoring, and research requirements that each cooperating nation must implement to be in compliance with the management plan;

d. A complete description of how stock survey data and fisheries data are used to establish annual catch and export quotas, including a full explanation of any models used and the assumptions underlying those models;

e. Procedures under which the nations may implement and enforce alternative management measures that achieve the same conservation benefits for beluga sturgeon as the standards mentioned in paragraph (b); and

f. A complete schedule by which nations must take particular actions to be in compliance with the plan.

The Service's Division of Scientific Authority will immediately review these basin-wide management plans upon receipt for completeness and clarity. If any elements of the management plans are missing or unclear, we will ask the appropriate range states to provide additional information within 60 days of the date we contact them. If the range states fail to respond or fail to submit basin-wide management plans by the specified deadline, or if we are unable to confirm that all range states are signatories to those plans, we will immediately suspend trade with all range states in the given basin (Caspian Sea or Black Sea) until we are satisfied that such management plans exist.

2. Within 6 months of the effective date of this special rule, if adopted, all range countries wishing to export beluga caviar and meat to the United States must submit copies of national legislation and national fishery

regulations pertaining to the harvest, trade, aquaculture, restocking, and processing of beluga sturgeon. These laws and regulations must exhibit clear means to implement the cooperative management plans mentioned in paragraph 1 above. Upon receipt, the Service's Division of Scientific Authority will immediately review these laws and regulations for completeness and clarity. If any elements of the national legislation or national fishery regulations are missing or unclear, we will ask the appropriate range states to provide additional information within 60 days of the date we contact them. If the range states fail to respond or fail to submit copies of national laws and regulations by the specified deadline, we will immediately suspend trade with the given range states until we are satisfied that such laws and regulations are in effect.

3. No later than November 1, 2005, and every year on that anniversary, all range states wishing to export beluga sturgeon products to the United States must submit an annual report to the Service, if this proposed rule is adopted. This annual report must contain, at a minimum:

a. A description of the specific fishery regulations that affect the harvest of *Huso huso* in the respective range country, with any changes from the previous year highlighted;

b. A description of any revisions to the cooperative management program mentioned above, including any new models, assumptions, or equations used to set harvest and export quotas;

c. Updated time-series of information on beluga sturgeon obtained from monitoring programs, including estimates of relative or absolute stock size, fishing mortality, natural mortality, spawning activity, habitat use, hatchery and restocking programs, or other relevant subjects;

d. A summary of law enforcement activities undertaken in the last year, and a description of any changes in programs to prevent poaching and smuggling;

e. A summary of the revenues generated by the commercial exploitation of beluga sturgeon in the respective range country, and a summary of any documented conservation benefits resulting from the commercial harvest program in that country (*e.g.*, revenues allocated to hatchery and re-stocking programs or research programs); and

f. Export data for the previous calendar year.

Starting in November 2005, the Service will conduct a review of information in the annual reports and any other pertinent information on wild beluga sturgeon conservation if the proposed rule is adopted. Thereafter, we will continue to conduct these reviews biennially. If any elements of the annual reports are missing or unclear, the Service will ask the appropriate range states to provide additional information within 60 days of the date we contact them. If the range states fail to respond or fail to submit annual reports by the specified deadline, we will immediately suspend trade with the given range states. We propose to use these reviews to determine whether range country management programs are leading to recovery of wild beluga sturgeon stocks.

Although we have no ability to regulate take or institute recovery plans for beluga sturgeon in the range countries, we have identified general short-term and long-term recovery objectives for beluga sturgeon in the Caspian and Black Seas. These objectives will help us gauge the efficacy of this special rule, and monitor progress toward beluga sturgeon restoration in the wild as indicated in the annual reports mentioned above. The short-term objective is to prevent further reduction of existing wild populations of beluga sturgeon. Baseline population indices for each beluga sturgeon stock are under development (Anonymous, 2002c) or in the planning stages (Anonymous, 2002a; ibid. 2002b), and changes in these indices will be evaluated over 3- to 5-year periods. The long-term recovery goal for beluga sturgeon is to establish self-sustaining stocks in the Caspian and Black Sea basins that can withstand directed fishing pressure. A self-sustaining stock is one in which the average rate of recruitment to the juvenile stage at least equals the average mortality rate across the population over a 12- to 17-year period (the period required for beluga sturgeon to reach maturity).

Based on the biennial review of annual reports, we propose to administratively suspend or restrict imports of beluga sturgeon products from the range countries if we determine that wild beluga sturgeon stock status worsens or threats to the species increase. Trade restrictions or suspensions may result basin-wide or for specific range countries under one or more of the following scenarios:

1. Failure to submit any of the reports, legislation, and management plans described above, or failure to respond to requests for additional information;

2. A change in regional cooperative management that threatens the recovery of wild beluga sturgeon;

3. A change in range country laws or regulations that compromises beluga sturgeon recovery or survival in the wild;

4. Adoption of scientifically unsound hatchery practices or restocking programs for beluga sturgeon;

5. A decline in wild *Huso huso* populations, as documented in national reports outlined above or the scientific literature, that goes unaddressed by regional or national management programs;

6. Failure to address poaching or smuggling in beluga sturgeon, their parts, or products in the range countries or re-exporting countries, as documented in national reports described above or other law enforcement sources;

7. Failure of the range countries to address the loss of beluga sturgeon habitat quality or quantity;

8. Failure of the range countries or re-exporting countries to follow the caviar labeling recommendations of the CITES Parties (currently embodied in Resolution Conf. 12.7);

9. Recommendations from the CITES Standing Committee to suspend trade in beluga sturgeon from one or more countries; or

10. Any other natural or human-induced phenomenon that threatens the survival or recovery of beluga sturgeon.

Under this proposed special rule, if adopted, we will decide whether to suspend trade in beluga sturgeon products for an entire basin or on a country-specific basis, including re-exporting countries. This decision, made by the Service's Division of Scientific Authority in consultation with relevant experts, will depend on the scope of the problem observed, the magnitude of the threat to wild beluga sturgeon, and whether remedial action is necessary at a local, national, or region-wide scale. Upon determination that a trade restriction or suspension is necessary, we will publish our findings in the **Federal Register** with the following information:

1. The problem(s) identified in the annual reports or other salient documents.

2. The scope of the problem and the number of nations involved.

3. The scope of the trade restriction or suspension we are imposing, including products covered, duration of the restriction or suspension, and criteria for lifting it.

4. How the public can provide input, make comments, and recommend remedial action to withdraw the trade measures imposed.

Effects of the Special Rule

Consistent with Sections 3(3) and 4(d) of the Act, this proposed special rule would amend 50 CFR 17.44 to allow importation, re-exportation, and foreign and interstate commerce of beluga sturgeon caviar and meat, without a threatened species permit otherwise required by 50 CFR part 17, if all requirements of the special rule and 50 CFR part 13 (General Permit Procedures), part 14 (Importation, Exportation, and Transportation of Wildlife), and part 23 (Endangered Species Convention—CITES) are met.

This proposed special rule does not end protection for the species. For permit exemptions under this special rule, beluga sturgeon caviar and meat will have to originate from fish taken in range countries that have complied with the management and reporting requirements mentioned above, beluga caviar must be labeled as per the recommendations of the CITES Parties (even for U.S. domestic trade), and all beluga sturgeon products must be accompanied by valid CITES Appendix-II export permits or re-export certificates. The special rule will not undermine conservation efforts for wild beluga sturgeon in the range countries since import, export, re-export, and interstate and foreign commerce (involving people under U.S. jurisdiction) in live *Huso huso* (usually destined for aquaculture operations outside the range countries) would still require a threatened species permit. Issuance of these permits is predicated on some direct benefit to wild populations of beluga sturgeon in the range countries.

Trade with the United States in beluga sturgeon products will be allowed only with countries that have designated both a CITES Management Authority and Scientific Authority, and have not been identified by the CITES Conference of the Parties, the CITES Standing Committee, or in a Notification from the CITES Secretariat as countries from which Parties are asked not to accept shipments of beluga sturgeon specimens or all CITES-listed species. This restriction will also apply to intermediary countries that re-export beluga sturgeon to the United States. The Service's Division of Management Authority will provide on request a list of those countries that have not designated either a Management Authority or a Scientific Authority, or that have been identified as a country from which Parties are asked not to accept shipments of specimens of any CITES-listed species that would include beluga sturgeon.

As noted above, this special rule exempts certain trade in beluga caviar or meat from the issuance of threatened species permits. We will consider issuing threatened species permits for the import, export, re-export of, or commerce in, other beluga sturgeon specimens when the activity enhances the conservation of the species in the wild or the other criteria for threatened species permits as described in 50 CFR 17.32. In addition, all exports, re-exports, and imports of beluga sturgeon specimens will require the presentation of valid CITES permits and certificates as per 50 CFR part 23.

As noted above, the Service's Division of Scientific Authority will conduct a review beginning in November 2005 and every 2 years thereafter based on information in the annual reports, and other available information, to determine whether range country and regional management programs are effectively achieving conservation benefits for wild beluga sturgeon populations. Trade restrictions or a trade suspension could be placed on a range country if the Service's Division of Scientific Authority administratively determines that the conservation or management status of beluga sturgeon in that country has changed such that continued recovery of the species is compromised. This provision gives the Service the ability to react effectively to potential conservation concerns that may emerge, such as persistent high levels of poaching in some areas, or changes in laws or regulations that appear to be detrimental to the species in the wild, or the lack of submission of the required annual reports and management plans.

We believe the issuance of this special rule is necessary and advisable for the conservation of the species for the following reasons:

1. Exempting the commercial trade in wild-origin and hatchery-origin beluga caviar and meat from permit requirements, with conditions, will expedite transfer of specimens into and out of the United States without compromising the species' recovery. This expedited trade offers an incentive to range countries to meet the requirements in this special rule, which are stricter than those imposed by CITES and provide more detailed information on stock status and management measures than CITES reports.

2. Without this special rule, we would prohibit all commercial trade in beluga caviar and meat unless approved via threatened species permits and appropriate CITES documentation. Such a restriction could reasonably be expected to: (a) Hamper or cease multilateral discussions between the United States and the range countries on beluga sturgeon conservation; (b) diminish or eliminate the revenue gained from U.S. beluga caviar markets that is used by range countries to support recovery programs for the species; (c) re-direct beluga sturgeon products from monitored international trade into unmonitored domestic markets; and (d) force us to rely on limited international trade data when assessing changes in harvest levels and market demand. All of these outcomes increase the conservation risks for the species while reducing the amount of data needed for informed decision making at the regional and international level.

3. Nearly all of the recommendations promulgated by the CITES Standing Committee for the range countries have been achieved or nearly achieved, according to the CITES Secretariat. We are unable to predict, therefore, how the CITES system will require updates and systematic changes in range country management programs for *Huso huso* after the Standing Committee reviews compliance with the 2001 recommendations (including the so-called "Paris Agreement") after 2004. If pressure from CITES processes abates, this special rule offers our most promising tool for getting information from the range countries and influencing the recovery programs for beluga sturgeon throughout its range.

Comments Solicited

The Service invites comments on this proposed rule. Comments should be sent to the Service's Division of Scientific Authority (*see* **ADDRESSES** section). Comments must be received by the date specified in the **DATES** section above.

Clarity of This Regulation

Executive Order 12866 requires each agency to write regulations that are easy to understand. We invite your comments on how to make this rule easier to understand, including answers to questions such as the following: (1) Are the requirements in the rule clearly stated? (2) Does the rule contain technical language or jargon that interferes with its clarity? (3) Does the format of the rule (grouping or order of sections, use of headings, paragraphing, etc.) aid or reduce its clarity? (4) Would the rule be easier to understand if it were divided into more (but shorter) sections? (5) Is the description of the rule in the "Supplementary Information" section of the preamble helpful in understanding the proposed rule? What else could we do to make the rule easier to understand? Send a copy of any comments that concern how we could make this rule easier to understand to Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street, NW., Washington, DC 20240. You also may e-mail the comments to *Exsec@ios.doi.gov*.

Required Determinations

A Record of Compliance was prepared for this proposed rule. A Record of Compliance certifies that a rulemaking action complies with the various statutory, Executive Order, and Department Manual requirements applicable to rulemaking. Without this proposed special rule, individuals subject to the jurisdiction of the United States would be prohibited from engaging in domestic, foreign, and international trade in beluga sturgeon meat and caviar except as permitted by Section 10 of the Act. Without this rule, anyone engaging in those activities would need to seek an authorization from us through a permit under section 10(a) of the Act. This process takes time and can involve an economic cost. The rule would allow these individuals to avoid the costs associated with abstaining from conducting these activities or with seeking a threatened species permit from us. These economic benefits, while important, do not rise to the level of "significant" under the following required determinations.

Regulatory Planning and Review

In accordance with the criteria in Executive Order 12866, the Office of Management and Budget has determined that this rule is not a significant regulatory action. This rule would not have an annual economic impact of more than $100 million, or significantly affect any economic sector, productivity, jobs, the environment, or other units of government. This rule would reduce the regulatory burden of the listing of the beluga sturgeon under the Act as a threatened species by providing certain exemptions to the section 9 prohibitions. These exemptions would reduce the economic costs of the listing; therefore, the economic effect of the rule would benefit citizens and the economy. This effect does not rise to the level of "significant" under Executive Order 12866. This rule will not create inconsistencies with other Federal agencies' actions. Other Federal agencies would be mostly unaffected by this proposed rule. This rule will not materially affect entitlements, grants, user fees, loan programs, or the rights and obligations of their recipients. Because this rule would allow individuals to continue otherwise prohibited activities without first obtaining individual authorization, the rule's impacts on affected individuals would be positive. This rule will not raise novel legal or policy issues. We have previously promulgated section 4(d) rules for other species.

Regulatory Flexibility Act

We have determined that this rule would not have a significant economic effect on a substantial number of small entities as defined under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). An initial regulatory flexibility analysis is not required, and a Small Entity Compliance Guide is not required. To assess the effects of the rule on small entities, the Service focused on the caviar import, re-export, and aquaculture industries in the United States because these are the entities most likely to be affected by the rule, particularly those engaged in beluga caviar importation, production, and distribution in the United States. In 2002, the most recent year for which we have import data, 15 businesses accounted for all of the foreign-source sturgeon caviar legally imported into the United States. It is possible that some of these businesses did not trade in beluga sturgeon. In those 15, the 10 largest importers accounted for 94 percent of all imported caviar (by weight), while the top 6 importers accounted for 85 percent of the U.S. trade (by weight). Illegal imports are not readily quantifiable, and were not addressed further in our analysis.

According to our analysis, no U.S. entities are involved in the commercial aquaculture of pure (*i.e.*, non-hybridized) *H. huso* products such as caviar and meat. However, at least one U.S. institution is conducting feasibility studies on the commercial aquaculture of hybrid "bester" sturgeon products. This type of aquaculture utilizes live beluga sturgeon and live sterlet (*Acipenser ruthenus*) to produce caviar in controlled, *ex situ* environments. Neither the threatened listing for beluga sturgeon nor the special rule affects trade in bester sturgeon products directly. However, there may be certain amounts of live beluga sturgeon required by these entities from the range countries. Given the apparently limited aquaculture use of beluga sturgeon, the section 9 prohibition on trade in live and aquacultured beluga sturgeon should have no significant economic impact in U.S. markets.

Small Business Regulatory Enforcement Fairness Act

This rule is not a major rule under 5 U.S.C. 804(2), the Small Business Regulatory Enforcement Fairness Act. This rule would not have an annual effect on the economy of $100 million or more; would not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; and would not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises.

The Service examined each of the four exemptions of the Act's section 9 trade prohibitions that would be created by the special rule (import, re-export, interstate commerce, and foreign commerce). We determined that the foreign commerce exemption would have little or no economic effect (*i.e.*, would not ease any significant cost that would have been imposed by section 9, without the rule). In foreign countries, this exemption would allow individuals and businesses subject to U.S. jurisdiction to engage in commerce involving beluga sturgeon products originating from range countries without the need for threatened species permits. We are not aware of such commerce currently, and therefore this exemption would create minimal benefits.

The Service also examined the impact of the special rule on import, re-export, and interstate commerce in beluga sturgeon products originating from a range country. This exemption would not have significant economic effects in regard to scientific samples or personal effects moving in and out of the United States, given our recorded low volume of such transactions. However, this exemption would create significant benefits to beluga sturgeon traders commercially importing, re-exporting, and selling (across State lines) beluga sturgeon caviar and meat originating from the range countries. Without the rule, section 9 would prevent all current import, re-export, and interstate commerce, and traders would receive no income from lucrative U.S. markets for beluga sturgeon meat or caviar. With the rule, this international and interstate commerce could continue with an estimated annual net income of $16 million to $39 million per year for the traders, a beneficial effect of the rule.

Unfunded Mandates Reform Act

In accordance with the Unfunded Mandates Reform Act (2 U.S.C. 1501, *et seq.*,) this rule would not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. This rule would not have a significant or unique effect on State, local, or tribal governments or the private sector. A Small Government Agency Plan is not required.

Takings

In accordance with Executive Order 12630, this rule does not have significant takings implications. By reducing the regulatory burden placed on affected individuals resulting from the listing of the beluga sturgeon as a threatened species, this rule would reduce the likelihood of potential takings. Affected individuals would have more freedom to pursue activities (*i.e.*, import and re-export) involving beluga sturgeon without first obtaining individual authorization.

Federalism

In accordance with Executive Order 13132, this rule does not have sufficient federalism implications to warrant the preparation of a federalism assessment.

Civil Justice Reform

In accordance with Executive Order 12988, the Office of the Solicitor has determined that this rule does not unduly burden the judicial system and meets the requirements of sections 3(a) and 3(b)(2) of the Executive Order.

Paperwork Reduction Act

Office of Management and Budget (OMB) regulations at 5 CFR 1320 implement provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*). The OMB regulations at 5 CFR 1320.3(c) define a "collection of information" as the obtaining of information by or for an agency by means of identical questions posed to, or identical reporting, recordkeeping, or disclosure requirements imposed on, 10 or more persons. Furthermore, 5 CFR 1320.3(c)(4) specifies that "10 or more persons" refers to the persons to whom a collection of information is addressed by the agency within any 12-month period. For purposes of this definition, employees of the Federal Government are not included. A Federal 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.

This rule refers to CITES permits required for the export to the United States of beluga sturgeon caviar and meat. Our CITES permit applications are already approved by OMB under OMB control number 1018–0093, which expires May 31, 2004. OMB is currently reviewing our request to renew the approval for OMB control number 1018–0093 for another 3 years.

In addition, this rule would newly require certain other information, including national management plans, national regulations, annual reports, and labeling of shipments, to be provided to the Service by countries wishing to export beluga sturgeon products to the United States. The new information requirements do not, however, require OMB approval under the Paperwork Reduction Act, as explained below.

Although we identify 11 countries in the current biological range of the beluga sturgeon, only 7 of these countries (Azerbaijan, Bulgaria, Iran, Kazakhstan, Romania, Russia, and Turkmenistan) currently have a national program to commercially harvest and export beluga sturgeon. In addition, Serbia and Montenegro (a federation bordering the Adriatic Sea) routinely declare catch and export quotas for beluga sturgeon, but the species is considered extirpated from the Adriatic Sea. Therefore, only those 7 countries with existing national harvest programs would be able to provide the information required by this rule to the Service. As such, the threshold of 10 or more respondents per year is not met, and OMB approval is not required. If, in the future, additional countries develop national programs to commercially harvest and export beluga sturgeon, and it therefore becomes necessary to collect information from 10 or more respondents per year, we will first obtain information collection approval from OMB.

National Environmental Policy Act

We have analyzed this rule in accordance with the criteria of the National Environmental Policy Act of 1969 (NEPA), and have determined that this rule does not constitute a major Federal action significantly affecting the quality of the human environment within the meaning of Section 102(2)(C) of the NEPA, and it would not involve unresolved conflicts concerning alternative uses of available resources (516 DM 2.3A). Therefore, this rule is categorically excluded under 516 DM 2, Appendix 1.10.

Government-to-Government Relationship With Tribes

In accordance with the President's memorandum of April 29, 1994, "Government-to-Government Relations With Native American Tribal Governments" (59 FR 22951) and E.O. 13175, we have evaluated possible effects on federally recognized Indian Tribes. We have determined that, because no Indian trust resources occur within the range of the beluga sturgeon, this rule would have no effects on federally recognized Indian Tribes.

Executive Order 13211

We have evaluated this proposed rule in accordance with E.O. 13211 and have determined that this rule would have no effects on energy supply, distribution, or use. Therefore, this action is not a significant energy action, and no Statement of Energy Effects is required.

Literature Cited

Anonymous, 2002a. Caspian Sea sturgeons. Interpretation and implementation of the Convention, significant trade in Appendix-II species. 47th meeting of the Standing Committee, 1–2 November 2002; Santiago, Chile. SC47 Doc. 11.

Anonymous, 2002b. Conservation of Acipenseriformes; implementation of Decisions 11.59 and 11.152. Notification to the Parties 2002/012. 6 March 2002; Geneva, Switzerland.

Anonymous, 2002c. Report on results of complex interstate all-Caspian Sea expedition on the assess of sturgeon species stocks. FSUI CaspNIRKh, Atyrau branch of KazNIRKh, AzerNIRKh, State Fishery Department of Turkmenistan, Iran Scientific Research Center (Shilat). Astrakhan, 2002.

ASMFC, 1998. Amendment 1 to the interstate fishery management plan for Atlantic sturgeon. Fishery management report no. 31 of the Atlantic States Marine Fisheries Commission. July 1998. 43 pp.

NMFS, 1998. Final recovery plan for the shortnose sturgeon, Acipenser brevirostrum. December 1998. U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Service. 104 pp.

USFWS and GSMFC, 1995. Gulf sturgeon recovery plan. U.S. Fish and Wildlife Service and Gulf States Marine Fisheries Commission. Atlanta, Georgia. 170 pp.

Author

The primary author of this rule is John Field, Division of Scientific Authority, 4401 North Fairfax Drive, Room 750, U.S. Fish and Wildlife Service, Arlington, VA 22203 [telephone, 703–358–1708].

List of Subjects in 50 CFR Part 17

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

Proposed Regulation Promulgation

For the reasons stated in the preamble, the Service hereby proposes to amend part 17, subpart B of chapter I, title 50 of the Code of Federal Regulations, as set forth below:

PART 17—[AMENDED]

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

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

2. In § 17.11(h) revise the entry for the "Sturgeon, beluga," under "Fishes," on the List of Endangered and Threatened Wildlife to read as follows:

§ 17.11 Endangered and threatened wildlife.

* * * * *

(h) * * *

Species		Historic Range	Vertebrate population where endangered or threatened	Status	When listed	Critical habitat	Special rules
Common name	Scientific name						
*	*	*	*	*	*	*	
FISHES							
*	*	*	*	*	*	*	
Sturgeon, beluga.	*Huso huso* ...	Azerbaijan, Bulgaria, Croatia, Czech Republic, Georgia, Hungary, Islamic Republic of Iran, Kazakhstan, Republic of Moldova, Romania, Russian Federation, Turkey, Turkmenistan, Ukraine, Yugoslavia (Caspian Sea, Black Sea, Adriatic Sea, Sea of Azov, and all rivers in their watersheds).	Entire	T	743	NA	17.44 (y)

3. Amend § 17.44 by adding paragraph (y) to read as follows:

§ 17.44 Special rules—fishes.

* * * * *

(y) *Beluga sturgeon.* This paragraph applies to the threatened beluga sturgeon (*Huso huso*).

(1) *How are various terms defined in this special rule?* In addition to the definitions specified in § 10.12 of subchapter B of this chapter, we define certain terms that specifically apply to the beluga sturgeon trade and this special rule as follows:

Aquacultured beluga sturgeon products. Eggs, larvae, fingerlings, or other products derived from *Huso huso* bred in captivity or grown in captivity for commercial purposes.

Beluga caviar. Processed unfertilized eggs from female *Huso huso* intended for human consumption, including products containing such eggs (*e.g.*, cosmetics).

Beluga meat. Excised muscle tissue of *Huso huso* destined for human consumption.

Black Sea. The contiguous waters of the Black Sea and the Sea of Azov.

CITES. The Convention on International Trade in Endangered Species of Wild Fauna and Flora.

Hatchery-origin beluga sturgeon. Specimens of Huso huso bred in captivity solely in the range countries, primarily for reintroduction and stock enhancement purposes.

Live beluga sturgeon. Any living specimen of *Huso huso*, including viable unfertilized or fertilized eggs, adults, fingerlings, and juveniles.

Range countries. Azerbaijan, Bulgaria, Georgia, Iran, Kazakhstan, Moldova, Romania, Russia, Turkey, Turkmenistan, and Ukraine.

Re-export. Export of beluga sturgeon specimens that were previously imported.

Wild beluga sturgeon. Specimens of *Huso huso* born and reared in the natural marine environment within the current or former geographic range of the species.

(2) *What activities involving beluga sturgeon are prohibited by this rule?*

(i) *International trade in beluga sturgeon.* Except as provided in paragraph (y)(3) of this section, all prohibitions and provisions of § 17.31(a) apply to the international trade in beluga sturgeon, including its parts and derivatives. This rule provides no exemption to the prohibitions and provisions of § 17.32 for aquacultured beluga sturgeon products produced outside the range countries or live beluga sturgeon.

(ii) *Trade without CITES documents.* Except as provided in paragraph (y)(3) of this section, you may not import, export, or re-export, or present for export or re-export beluga sturgeon or beluga sturgeon products without valid CITES permits and other permits and licenses issued under parts 13, 17, and 23 of this chapter.

(iii) *Commercial activity.* Except as provided in paragraph (y)(3) of this section and § 17.32, you may not sell or offer for sale, deliver, receive, carry, transport, or ship in interstate or foreign commerce in the course of a commercial activity any beluga sturgeon or beluga sturgeon products.

(iv) It is unlawful for any person subject to the jurisdiction of the United States to commit, attempt to commit, solicit to commit, or cause to be committed any acts described in paragraphs (y)(2)(ii) and (iii) of this section.

(3) *What activities are exempted from threatened species permits by this rule?*

(i) *Import, re-export, and interstate commerce involving certain caviar and meat obtained from beluga sturgeon.* You may import, re-export, or conduct interstate or foreign commerce in beluga sturgeon caviar and meat without a threatened species permit issued according to § 17.32 only if the caviar and meat are derived from wild or hatchery-origin beluga sturgeon that were caught and processed in the range countries. Also, the provisions in parts 13, 14, and 23 of this chapter and the following requirements must be met:

(A) Any beluga caviar must comply with all CITES labeling requirements, as defined in relevant Resolutions or Decisions of the Conference of the Parties, including beluga caviar in interstate commerce in the United States. All individuals or businesses in the United States wishing to engage in interstate domestic commerce of beluga sturgeon caviar must follow the CITES caviar labeling requirements.

(B) The shipment must be accompanied by a valid CITES permit or certificate.

(C) For each shipment covered by this exception, the country of origin and each country of re-export, and the country of import involved in the trade of a particular shipment, must have designated both a CITES Management Authority and Scientific Authority, and have not been identified by the CITES Conference of the Parties, the CITES Standing Committee, or in a Notification from the CITES Secretariat as a country from which Parties should not accept permits for beluga sturgeon or all CITES-listed species in general.

(D) The range country from which the beluga sturgeon caviar or meat originated has complied with all of the requirements shown in paragraph (y)(4) of this section, and none of the exporting, importing, or re-exporting countries involved in the commercial activity has been subject to an administrative trade restriction or suspension as outlined in paragraphs (y)(5) and (6) of this section.

(ii) *Import and re-export of noncommercial personal or household effects.* Article VII(3) of the CITES Convention recognizes a limited exemption for the international movement of personal and household effects, including specimens of beluga sturgeon.

(A) *Stricter national measures.* The exemption for personal and household effects does not apply if a country prohibits or restricts the import, export, or re-export of the item.

(*1*) You or your shipment must be accompanied by any document required by a country under its stricter national measures.

(*2*) In the United States, you must obtain any permission needed under other regulations in this subchapter.

(B) *Required CITES documents.* You must obtain a CITES document for personal or household effects and meet the requirements of this part if one of the following applies:

(*1*) The Management Authority of the importing, exporting, or re-exporting country requires a CITES document.

(*2*) You or your shipment does not meet all of the conditions for an exemption as provided in paragraphs (y)(3)(ii)(C) through (E) of this section.

(*3*) The personal or household effect exceeds 250 grams of beluga caviar. To import or re-export more than 250 grams, you must have a valid CITES document for the entire quantity.

(C) *Personal effects.* You do not need a CITES document to import or re-export any part, product, derivative, or manufactured article of a legally acquired beluga sturgeon specimen to or from the United States if all of the following conditions are met:

(*1*) No living beluga sturgeon is included.

(*2*) You personally own and possess the item for noncommercial purposes, including any item intended as a personal gift.

(*3*) The item and quantity of items are reasonably necessary or appropriate for the nature of your trip or stay.

(*4*) You are either wearing the item as clothing or an accessory or taking it as part of your personal baggage, which is being carried by you or checked as baggage on the same plane, boat, car, or train as you.

(*5*) The item was not mailed or shipped separately.

(D) *Household effects.* You do not need a CITES document to import or re-export any part, product, derivative, or manufactured article of a legally acquired beluga sturgeon specimen that is part of a shipment of your household effects when moving your residence to or from the United States, if all of the following conditions are met:

(*1*) No living beluga sturgeon is included.

(*2*) You personally own the item and are moving it for noncommercial purposes.

(*3*) The item and quantity of items are reasonably necessary or appropriate for household use.

(*4*) You import or re-export your household effects within 1 year of changing your residence from one country to another.

(*5*) The shipment, or shipments if you cannot move all of your household effects at one time, contains only items purchased, inherited, or otherwise acquired before you moved your residence.

(E) *Trade restrictions.* Regardless of the provisions above for personal and household effects, any trade suspension or trade restriction administratively imposed by the Service under paragraphs (y)(5) or (6) of this section could also apply to personal and household effects of beluga caviar.

(4) *What must beluga sturgeon range countries do to be authorized under the special rule to export to the United States?* The following requirements apply to the range countries wishing to export beluga caviar or beluga meat to the United States without the need for a threatened species permit issued under § 17.32. These requirements apply to all shipments of beluga caviar and beluga meat that originate in the range countries, even if the shipments are re-exported to the United States via an intermediary country. (See paragraph (y)(6) of this section for more information on the Service's biennial reviews under the special rule.)

(i) *Basin-wide beluga sturgeon management plans.* By [*insert date 6 months after the effective date of this special rule*], each range country wishing to export beluga caviar or beluga meat to the United States without the need for a threatened species permit issued under § 17.32 must submit a copy of a cooperative management plan for their respective basin (*i.e.*, Black Sea or Caspian Sea) that addresses *Huso huso* conservation. Each of these two basin-wide management plans must be agreed to by all of the range countries (not just exporting nations) in the Black Sea or the Caspian Sea, as appropriate. Upon receipt, the Service's Division of Scientific Authority will immediately review these basin-wide management plans for completeness and clarity. If any elements of the management plans are missing or unclear, we will ask the appropriate range states to provide additional information within 60 days of the date we contact them. If the range states fail to respond or fail to submit basin-wide management plans by the specified deadline, or if we are unable to confirm that all range states are signatories to those plans, we will immediately suspend trade with all range states in the given basin (Caspian Sea or Black Sea) until we are satisfied that such management plans exist. Submission of documents in English may help expedite the Service's review. These cooperative management plans must contain the following elements:

(A) A clear statement of the recovery and management objectives of the plan, including a specification of the stock(s) concerned, a definition of what constitutes over-fishing for that stock, and a rebuilding objective and schedule for that stock;

(B) A statement of standard regulations (*e.g.*, size limits, target harvest rates, quotas, seasons, fishing gear, or effort caps) to be utilized by the nations involved;

(C) A complete statement of the specific regulatory, monitoring, and research requirements that each cooperating nation must implement to be in compliance with the management plan;

(D) A complete description of how stock survey data and fisheries data are used to establish annual catch and export quotas, including a full explanation of any models used and the assumptions underlying those models;

(E) Procedures under which the nations may implement and enforce alternative management measures that achieve the same conservation benefits for beluga sturgeon as the standards mentioned in paragraph (y)(4)(i)(B) of this section; and

(F) A complete schedule by which nations must take particular actions to be in compliance with the plan.

(ii) *National regulations.* By [*insert date 6 months after the effective date of this special rule*], each range country wishing to export beluga caviar or beluga meat to the United States under this special rule must provide us with copies of national legislation and regulations that implement the basin-wide cooperative management plan described in paragraph (y)(4)(i) of this section, including regulations pertaining to the harvest, trade, aquaculture, restocking, and processing of beluga sturgeon. Upon receipt, the Service's Division of Scientific Authority will immediately review these basin-wide management plans for completeness and clarity. If any elements of the national legislation or national fishery regulations are missing or unclear, we will ask the appropriate range states to provide additional information within 60 days of the date we contact them. If the range states fail to respond or fail to submit copies of national laws and regulations by the specified deadline, we will immediately suspend trade with the given range states until we are satisfied that such laws and regulations are in effect. Submission of documents in English may help expedite the Service's review.

(iii) *Annual report.* Range country governments wishing to export specimens of beluga sturgeon caviar or meat to the United States under this special rule will need to provide an annual report containing the most recent information available on the status of the species, following the information guidelines specified below. The Service must receive the first annual report no later than November 1, 2005, and every year thereafter on the anniversary of that date. Starting in November 2005, and thereafter on a biennial basis, the Service will conduct a review of information in the annual reports and any other pertinent information on wild beluga sturgeon conservation. If any elements of the annual reports are missing or unclear, the Service will ask the appropriate range states to provide additional information within 60 days of the date we contact them. If the range states fail to respond or fail to submit annual reports by the specified deadline, we will immediately suspend trade with the given range states. Submission of documents in English may help expedite the Service's review. We propose to use these reviews to determine whether range country management programs are leading to recovery of wild beluga sturgeon stocks. For each range country, the following information must be provided in the annual report:

(A) A description of the specific fishery regulations that affect the harvest of *Huso huso* in the respective range country, with any changes from the previous year highlighted;

(B) A description of any revisions to the cooperative management program mentioned in paragraph (y)(4)(i) of this section, including any new models, assumptions, or equations used to set harvest and export quotas;

(C) New information obtained in the last year on beluga sturgeon distribution, stock size, models used for quota-setting, spawning activity, habitat use, hatchery programs and results, or other relevant subjects;

(D) A summary of law enforcement activities undertaken in the last year, and a description of any changes in programs to prevent poaching and smuggling;

(E) A summary of the revenues generated by the commercial exploitation of beluga sturgeon in the respective range country, and a summary of any documented conservation benefits resulting from the commercial harvest program in that country (*e.g.*, revenues allocated to hatchery/re-stocking programs or research programs); and

(F) Export data for the previous calendar year.

(iv) *Caviar labeling.* All caviar shipments imported into the United States must follow the CITES caviar labeling requirements as agreed to in the relevant Resolutions and Decisions of the CITES Parties.

(v) *CITES compliance.* Except as provided in paragraph (y)(3)(ii) of this section, all shipments of beluga sturgeon specimens, including those exempted from threatened species permits under this special rule, will require accompanying valid CITES permits and certificates.

(vi) *Initial reporting period.* Until [*insert date 6 months after the effective date of this rule*], no threatened species permits will be required for the import, re-export, or interstate or foreign commerce of beluga sturgeon caviar and meat that originated in the range countries, in order to provide the range countries time to submit the required documentation. After this 6-month period, the exemption from threatened species permits will continue only under the terms and conditions specified in paragraphs (y)(4)(i) through (v) of this section.

(5) *How will the Service inform the public of CITES restrictions in trade of beluga sturgeon?* We will issue an information bulletin that identifies a restriction or suspension of trade in specimens of beluga sturgeon and post it on our websites (*http://le.fws.gov* and *http://international.fws.gov*) and at our staffed wildlife ports of entry if any criterion in paragraphs (y)(5)(i) or (ii) of this section is met:

(i) The country is listed in a Notification to the Parties by the CITES Secretariat as lacking a designated Management Authority or Scientific Authority for the issuance of valid CITES documents or their equivalent.

(ii) The country is identified in any action adopted by the Conference of the Parties to the Convention, the Convention's Standing Committee, or in a Notification issued by the CITES Secretariat, as a country from which Parties are asked not to accept shipments of specimens of beluga sturgeon or all CITES-listed species. A listing of all countries that have not designated both a Management Authority and Scientific Authority, or that have been identified as a country from which Parties should not accept permits, is available by writing to: Division of Management Authority, U.S. Fish and Wildlife Service, 4401 N. Fairfax Drive, Room 700, Arlington, VA 22203.

(6) *How will the Service set trade restrictions or prohibitions under the special rule?* The Service's Division of Scientific Authority will conduct a biennial review of beluga sturgeon conservation based on information in the cooperative basin-wide management plans, national regulations and laws, and annual reports (submitted as per paragraph (y)(4) of this section). We will combine that review with a review of other relevant sources (*e.g.*, scientific literature, law enforcement data, government-to-government consultations) to determine whether range country management programs are effectively achieving conservation benefits for beluga sturgeon. Based on this information, or the failure to obtain it, the Service may restrict trade from a range country, a re-exporting intermediary country, or an entire basin (*i.e.*, the Caspian Sea or Black Sea) if we determine that the conservation or management status of beluga sturgeon has changed and the continued recovery of beluga sturgeon in that country or basin may be compromised. The decision to restrict trade in beluga sturgeon products on a national, basin, or region-wide scale will depend on the scope of the problem observed, the magnitude of the threat to wild beluga sturgeon, and whether remedial action is necessary at a national, basin, or region-wide scale.

(i) Trade restrictions or suspensions may result basin-wide or for specific range countries under one or more of the following scenarios:

(A) Failure to submit any of the reports, legislation, and management plans described above, or failure to respond to requests for additional information;

(B) A change in regional cooperative management that threatens the recovery of wild beluga sturgeon;

(C) A change in range country laws or regulations that compromises beluga sturgeon recovery or survival in the wild;

(D) Adoption of scientifically unsound hatchery practices or restocking programs for beluga sturgeon;

(E) A decline in wild *Huso huso* populations, as documented in national reports outlined above or the scientific literature, that goes unaddressed by regional or national management programs;

(F) Failure to address poaching or smuggling in beluga sturgeon, their parts, or products in the range countries or re-exporting countries, as documented in national reports described above or other law enforcement sources;

(G) Failure of the range countries to address the loss of beluga sturgeon habitat quality or quantity;

(H) Failure of the range countries or re-exporting countries to follow the caviar labeling recommendations of the CITES Parties (currently embodied in Resolution Conf. 12.7);

(I) Recommendations from the CITES Standing Committee to suspend trade in beluga sturgeon from one or more countries; or

(J) Any other natural or human-induced phenomenon that threatens the survival or recovery of beluga sturgeon.

(ii) We will publish an information notice in the **Federal Register** if the Service's Division of Scientific Authority administratively suspends or restricts imports of beluga sturgeon products from the range countries or re-exports of beluga sturgeon products from the United States after determining that wild beluga sturgeon stock status worsens or threats to the species increase.

Dated: June 22, 2004.

Craig Manson,

Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 04–14795 Filed 6–25–04; 11:50 am]

BILLING CODE 4310–55–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 216

[Docket No. 040323099–4099–01; I.D. 072699A]

RIN 0648–AR99

Taking and Importing Marine Mammals; Taking Marine Mammals Incidental to Navy Operations of Surveillance Towed Array Sensor System Low Frequency Active Sonar

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

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS proposes to amend its regulations governing the taking of marine mammals incidental to operations of the U.S. Navy's Surveillance Towed Array Sensor System Low Frequency Active (SURTASS LFA) sonar to implement provisions of the National Defense Authorization Act of 2004.

DATES: Comments and information must be received no later than July 29, 2004.

ADDRESSES: Comments should be addressed to P. Michael Payne, Chief, Marine Mammal Conservation Division, Office of Protected Resources, National Marine Fisheries Service, 1315 East-West Highway, Silver Spring, MD 20910–3225. Comments also may be submitted by e-mail. The e-mail mailbox address is *0648–AR99@noaa.gov.* Include in the subject line of the e-mail the following document identifier: 0648–AR99.

FOR FURTHER INFORMATION CONTACT: Kenneth R. Hollingshead, Office of Protected Resources, NMFS, (301) 713–2055, ext 128.

SUPPLEMENTARY INFORMATION:

Background

SURTASS LFA Sonar Rulemaking History

On August 12, 1999, NMFS received an application from the U.S. Navy requesting authorization under section 101(a)(5)(A) of the MMPA for the taking, by harassment, of marine mammals incidental to deploying the SURTASS LFA sonar system for training, testing, and routine military operations within the world's oceans except Arctic and Antarctic waters (see 64 FR 57026, October 22, 1999). NMFS issued a proposed rule on March 19, 2001 (66 FR 15375), and a final rule on July 16, 2002, (67 FR 46712), governing the taking of marine mammals incidental to Navy SURTASS LFA sonar operations. That final rule became effective on August 15, 2002, and remains in effect until August 15, 2007. Pursuant to the final rule, on August 16, 2002, NMFS issued a 1–year Letter of Authorization (LOA) to the Navy authorizing the taking of specified marine mammals within the specified areas of operation (67 FR 55818; August 30, 2002). Subsequently, the Navy applied for and received two additional LOAs covering two SURTASS LFA sonar systems from August 16, 2003, to August 15, 2004 (68 FR 50123; August 20, 2003). Additional information regarding NMFS' decision to authorize the taking of marine mammals incidental to Navy SURTASS LFA sonar operations is contained in the proposed and final rules and the LOAs and is not repeated here.

National Defense Authorization Act

On November 24, 2003, the President signed into law the National Defense Authorization Act of 2004 (NDAA) (Public Law 108–136). Included in this law were amendments to the Marine Mammal Protection Act (MMPA; 16 U.S.C. 1361 *et seq.*) that apply where a "military readiness activity" is concerned. Of specific importance for the SURTASS LFA sonar take authorization, the NDAA amended section 101(a)(5) of the MMPA, which governs the taking of marine mammals incidental to otherwise lawful activities.

Prior to the NDAA amendments, section 101(a)(5)(A) of the MMPA directed the Secretary of Commerce to allow, upon request, the incidental but not intentional taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if the Secretary finds that the total of such taking will have a negligible impact on the species or stock and will not have an unmitigable adverse impact on the availability of the species or stock of marine mammal for subsistence uses and regulations are issued. The NDAA amended section 101(a)(5) of the MMPA to exempt military readiness activities from the "specified geographical region" and "small numbers" requirements. The term "military readiness activity" is defined in Public Law 107–314 (16 U.S.C. 703 note) to include all training and operations of the Armed Forces that relate to combat; and the adequate and realistic testing of military equipment, vehicles, weapons and sensors for proper operation and suitability for combat use. The term expressly does not include the routine operation of installation operating support functions, such as military offices, military exchanges, commissaries, water treatment facilities, storage facilities, schools, housing, motor pools, laundries, morale, welfare and recreation activities, shops, and mess halls; the operation of industrial activities; or the construction or demolition of facilities used for a military readiness activity.

Proposed Action

NMFS and the Navy have determined that the Navy's SURTASS LFA sonar testing and training operations that are the subject of NMFS' July 16, 2002, final rule constitute a military readiness activity because those activities constitute "training and operations of the Armed Forces that relate to combat" and constitute "adequate and realistic testing of military equipment, vehicles, weapons and sensors for proper operation and suitability for combat use." Refer also to 67 FR 46712 ("Summary of Request") and 67 FR 46716–46717 (Comment and Response AC1). Accordingly, NMFS proposes to amend its rule and regulations governing the taking of marine mammals incidental to SURTASS LFA sonar testing and training operations to remove reference, in 50 CFR part 216, subpart Q, to "small numbers" and "specified geographical region," as those MMPA 101(a)(5)(A) terms no longer apply to the SURTASS LFA sonar testing and training operations covered by the final rule. It is necessary to amend the final rule for SURTASS LFA sonar because that rule no longer reflects the current requirements of the MMPA. Specifically, NMFS proposes to amend 50 CFR 216.180(a); 216.184(e)(2) (technical correction only); 216.187(c)(2) and (c)(4); 216.188(b)(2) and (c); and 216.189(a).

Although the MMPA no longer requires the identification of a "specified geographical region" in which military readiness activities will occur, information regarding where the Navy will operate SURTASS LFA sonar remains necessary for NMFS to make its required negligible impact determination and to prescribe appropriate mitigation and monitoring. In that regard, this proposed amendment would only make it clear that identification of a "specified geographical region" is no longer a statutory requirement for SURTASS LFA sonar operations covered under the final rule.

Similarly, although the "small numbers" requirement no longer applies to military readiness activities, information regarding estimates of anticipated take will remain necessary for NMFS' negligible impact determinations.

Information Solicited

NMFS requests that interested persons submit comments, information, and suggestions concerning this proposed action. Commenters are requested to restrict comments and recommendations to the scope of this action. Comments on issues beyond the scope of this proposed rule will not be considered in developing a final determination on this action.

Determinations

This proposed rule amendment would not alter the determination that SURTASS LFA sonar operations would have a negligible impact on the affected species or stocks of marine mammals made by NMFS in its SURTASS LFA sonar final rule (67 FR 46712, July 16, 2002). Nor would it change NMFS' determination that the activity covered under the final rule will not have an unmitigable adverse impact on subsistence uses. These determinations would remain the same because the Navy's activity covered under the final rule has not changed. Under the proposed rule amendment the Navy must still apply for LOAs, and NMFS must still find that the total taking by the Navy's proposed activity as a whole will have no more than a negligible impact and will not have an unmitigable adverse impact on the availability of marine mammal species or stocks for subsistence uses.

National Environmental Policy Act (NEPA)

This proposed amendment does not change the activity that was analyzed in the Navy's Final Environmental Impact Statement on SURTASS LFA sonar, approved by the Deputy Assistant Secretary of the Navy (Environment) in the SURTASS LFA sonar Record of Decision (67 FR 48145; July 23, 2002) and adopted by NMFS (67 FR 46712, July 16, 2002).

Endangered Species Act (ESA)

This proposed amendment does not change the activity whose effects were analyzed in NMFS' biological opinions on SURTASS LFA sonar.

Classification

This action has been determined to be significant for purposes of Executive Order 12866.

The Chief Counsel for Regulation of the Department of Commerce has certified to the Chief Counsel for Advocacy of the Small Business Administration that this action, if adopted, would not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act. This proposed rule removes some of the regulatory requirements applicable to the Navy. This proposed rule would affect only the U.S. Navy which is not a small entity. There may be a few small entities that provide services related to the Navy's SURTASS LFA sonar activities and the requirements under NMFS' original rule, but this proposed rule would not affect those activities as they would all continue to operate in the same manner. As a result no regulatory flexibility analysis was prepared.

List of Subjects in 50 CFR Part 216

Exports, Fish, Imports, Indians, Labeling, Marine mammals, Penalties, Reporting and recordkeeping requirements, Seafood, Transportation.

Dated: June 24, 2004.

Rebecca Lent,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons discussed in the preamble, 50 CFR part 216 is proposed to be amended as follows:

PART 216—REGULATIONS GOVERNING THE TAKING AND IMPORTING OF MARINE MAMMALS

1. The authority citation for part 216 continues to read as follows:

Authority: 16 U.S.C. 1361 *et seq.*, unless otherwise noted.

2. In § 216.180, the section heading and paragraph (a) are revised to read as follows:

§ 216.180 Specified activity.

* * * * *

(a) Subject to the limitations in § 216.184(e), the incidental taking by harassment may be authorized in the following areas as specified in a Letter of Authorization (see also Figure 1):

(1) North Atlantic Ocean:

(i) Western North Atlantic, from 35 deg. N. lat. north to a line between Cape Chidley, Labrador northeast to Nuuk, Greenland, and from the North American continent east to 41 deg. W. long. (Area A); and

(ii) Eastern North Atlantic, from 35 deg. N. lat. north to 72 deg. N. lat. and 41 deg. W. long. east to the European continent (Area B);

(2) Mediterranean Sea (Area C);

(3) North Pacific Ocean:

(i) Western North Pacific, from 20 deg. N. lat. north to the Aleutian Island chain and the Sea of Okhotsk, and from the Asian continent east to 175 deg. W. long. (Area D); and

(ii) Eastern North Pacific, from 42 deg. N. lat. north to Alaska and the south side of the Aleutian Islands and from the North American continent west to 175 deg. W. long. (Area E);

(4) Central Atlantic Ocean:

(i) Eastern Central Atlantic, from 7 deg. S. lat. north to 35 deg. N. lat. and from the African continent west to 40 deg. W. long. between 5 deg. N. lat. and 35 deg. N. lat., to 30 deg. W. long. between 0 deg. lat. and 5 deg. N. lat., and to 20 deg. W. long. between 7 deg. S. lat. and 0 deg. lat. (Area F); and

(ii) Western Central Atlantic, from 5 deg. N. lat. north to 35 deg. N. lat., and from the American continent, east to 40 deg. W. long. (Area G);

(5) Indian Ocean:

(i) Eastern Indian Ocean, from 60 deg. S. lat. north to the Bay of Bengal, and Asian continent, and from 80 deg. E. long. east to the Asian continent, the Sunda Islands and Australia and to 150 deg. E. long. (Area H1); and

(ii) Western Indian Ocean, from 60 deg. S. lat. north to the Arabian Sea, and from 30 deg. E. long. east to 80 deg. E. long. (Area H2);

(6) Central Pacific Ocean:

(i) Western Central Pacific, from 175 deg. W. long., east to the Asian continent and Indonesia, and from 10 deg. S. lat., north to 20 deg. N. lat. (Area I);

(ii) Central Pacific, from 10 deg. S. lat., north to 42 deg. N. lat. between 175 deg. W. long. and 130 deg. W. long. (Area J1); and

(iii) Eastern Central Pacific, from 5 deg. S. lat. north along the American coastline to 42 deg. N. lat., from 130 deg. W. long. along 10 deg. S. lat. to 105 deg. W. long., from 10 deg. S. lat. along 105 deg. W. long. to 5 deg. S. lat., from 105 deg. W. long. along 5 deg. S. lat. to the South American coastline, from 130 deg. W. long. along 42 deg. N. lat. to the North American coastline and from 42 deg. N. lat. to 10 deg. S. lat. along the 130 deg. W. long. line (Area J2);

(7) South Pacific Ocean:

(i) Western South Pacific from 60 deg. S. lat. north to 10 deg. S. lat. and from the east coast of Australia in the north and 150 deg. E. long. south of Australia east to 105 deg. W. long. (Area K); and

(ii) Eastern South Pacific from 60 deg. S. lat. north to 5 deg. S. lat. and from the 105 deg. W. long. east to the South American coastline in the north and 70 deg. W. long. in the south (Area L);

(8) South Atlantic Ocean:

(i) Western South Atlantic, from 60 deg. S. lat. north to 5 deg. N. lat. in the area west of 30 deg. W. long., and from 60 deg. S. lat. north to 0 deg. lat. in the area east of 30 deg. W. long. and from the South American continent east to 30 deg. W. long. between 0 deg. And 5 deg. N. lat. and east to 20 deg. W. long. between 0 deg. and 60 deg. S. lat. (Area M); and

(ii) East South Atlantic from 60 deg. S. lat. north to 7 deg. S. lat. and from 20 deg. W. long. east to the African coastline in the north and 30 deg. E. long. south of the continent (Area N).

* * * * *

3. In 216.184, paragraph (e)(2) is revised to read as follows:

§ 216.184 Mitigation.

* * * * *

(e) * * *

(2) Within any offshore area that has been designated asbiologically important for marine mammals under § 216.184(f), during the biologically important season for that particular area;

* * * * *

4. In § 216.187, paragraphs (c)(1), (c)(2) and (c)(4) are revised to read as follows:

§ 216.187 Applications for Letters of Authorization.

* * * * *

(c) * * *

(1) The date(s), duration, and the area(s) where the vessel's activity will occur;

(2) The species and/or stock(s) of marine mammals likely to be found within each area;

* * * * *

(4) The estimated percentage of marine mammal species/stocks potentially affected in each area for the 12–month period of effectiveness of the Letter of Authorization; and

* * * * *

5. In § 216.188, paragraphs (b)(2) and (c) are revised to read as follows:

§ 216.188 Letters of Authorization.

* * * * *

(b) * * *

(2) The area(s) where the vessel's activities will occur;

* * * * *

(c) Issuance of each Letter of Authorization will be based on a determination that the total number of marine mammals taken by the activity specified in § 216.180 as a whole will have no more than a negligible impact on the species or stock of affected marine mammal(s), and that the total taking will not have an unmitigable adverse impact on the availability of species or stocks of marine mammals for taking for subsistence uses.

* * * * *

6. In § 216.189, paragraph (a)(5) is revised and a new graphic is added to the end of the section to read as follows:

§ 216.189 Renewal of Letters of Authorization.

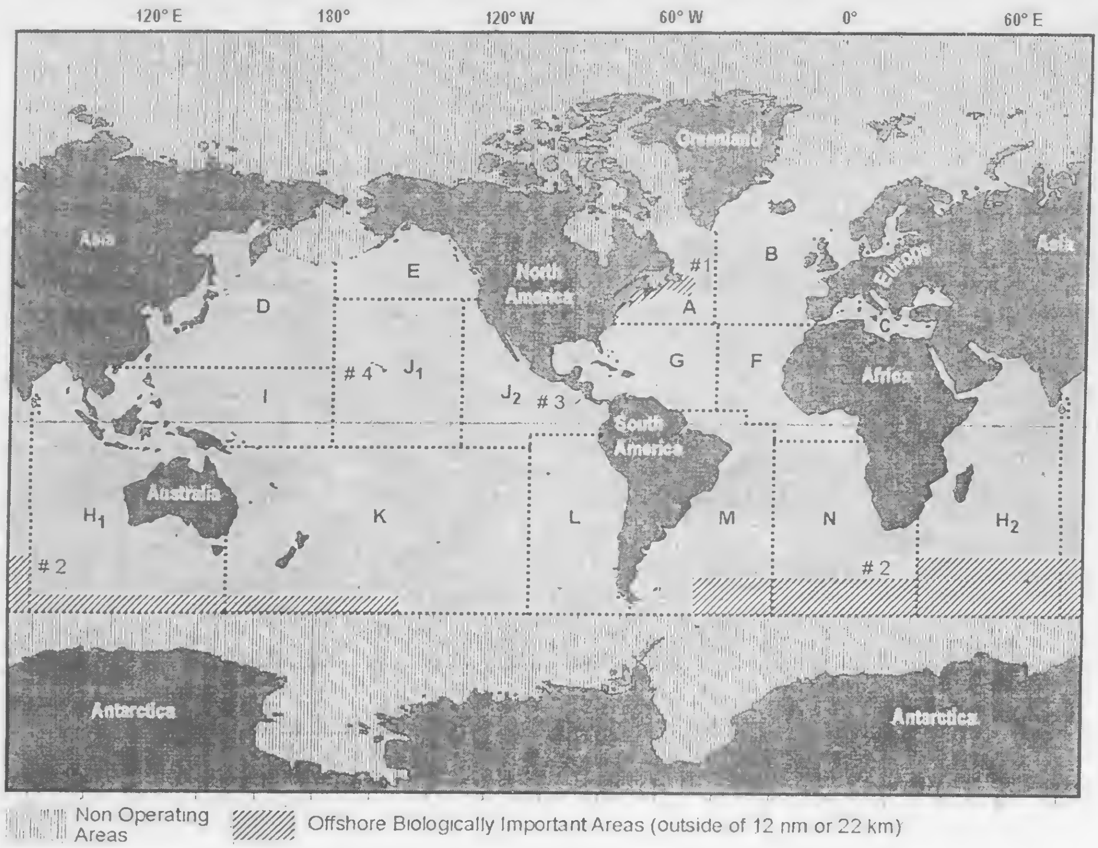
* * * * *

(a) * * *

(5) A determination by NMFS that the total number of marine mammals taken by the activity specified in § 216.180 as a whole will have no more than a negligible impact on the species or stock of affected marine mammal(s), and that the total taking will not have an unmitigable adverse impact on the availability of species or stocks of marine mammals for taking for subsistence uses.

* * * * *

BILLING CODE 3510–22–S



[FR Doc. 04–14718 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–22–C

Notices

Federal Register
Vol. 69, No. 124
Tuesday, June 29, 2004

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collections Being Reviewed by the U.S. Agency for International Development; Comments Requested

SUMMARY: U.S. Agency for International Development (USAID) is making efforts to reduce the paperwork burden. USAID invites the general public and other Federal agencies to take this opportunity to comment on the following proposed and/or continuing information collections, as required by the Paperwork Reduction Act for 1995. Comments are requested concerning: (a) Whether the proposed or continuing collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the burden estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Submit comments on or before August 30, 2004.

FOR FURTHER INFORMATION CONTACT: Beverly Johnson, Bureau for Management, Office of Administrative Services, Information and Records Division, U.S. Agency for International Development, Room 2.07–106, RRB, Washington, DC 20523, (202) 712–1365 or via e-mail *bjohnson@usaid.gov.*

SUPPLEMENTARY INFORMATION:

OMB No.: OMB 0412–0554.

Form No.: None.

Title: Training Results and Information Network (TraiNet).

Type of Review: Renewal of Information Collection.

Purpose: The purpose of this information collection is to enable the planning and reporting of information on all USAID training activities, including in-country training. Data collected by USAID and/or its partners via TraiNet includes measures of results and performance monitoring, training participant and program identification, and costs and cost-sharing.

Annual Reporting Burden:

Respondents: 374.

Total annual responses: 15, 720.

Total annual hours requested: 2,630 hours.

Dated: June 22, 2004.

Joanne Paskar,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 04–14688 Filed 6–28–04; 8:45 am]

BILLING CODE 6116–01–M

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collections Being Reviewed by the U.S. Agency for International Development; Comments Requested

SUMMARY: U.S. Agency for International Development (USAID) is making efforts to reduce the paperwork burden. USAID invites the general public and other Federal agencies to take this opportunity to comment on the following proposed and/or continuing information collections, as required by the Paperwork Reduction Act for 1995. Comments are requested concerning: (a) Whether the proposed or continuing collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the burden estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Submit comments on or before August 30, 2004.

FOR FURTHER INFORMATION CONTACT: Beverly Johnson, Bureau for Management, Office of Administrative Services, Information and Records Division, U.S. Agency for International Development, Room 2.07–106, RRB, Washington, DC, 20523, (202) 712–1365 or via e-mail *bjohnson@usaid.gov.*

SUPPLEMENTARY INFORMATION:

OMB No.: OMB 0412–0017.

Form No.: AID 1440–3.

Title: Contractor's Certificate and Agreement with the U.S. Agency for International Development/Contractor's Invoice and Contract Abstract.

Type of Review: Renewal of Information Collection.

Purpose: USAID finances host country contracts, for technical and professional services and for the construction of physical facilities, between the contractors for such services and entities in the country receiving assistance under loan or grant agreements with the recipient country. USAID is not a party to these contracts, and the contracts are not subject to the FAR. In its role as the financing agency, USAID needs some means of collecting information directly from the contractors supplying such services so that it may take appropriate action in the event that the contractor does not comply with applicable USAID regulations. The information collection, recordkeeping, and reporting requirements are necessary to assure that USAID funds are expended in accordance with statutory requirements and USAID policies.

Annual Reporting Burden:

Respondents: 25.

Total annual responses: 300.

Total annual hours requested: 175 hours.

Dated: June 22, 2004.

Joanne Pasker,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 04–14689 Filed 6–28–04; 8:45 am]

BILLING CODE 6116–01–M

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collections Being Reviewed by the U.S. Agency for International Development; Comments Requested

SUMMARY: U.S. Agency for International Development (USAID) is making efforts to reduce the paperwork burden. USAID invites the general public and other Federal agencies to take this opportunity to comment on the following proposed and/or continuing information collections, as required by the Paperwork Reduction Act for 1995. Comments are requested concerning: (a) Whether the proposed or continuing collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the burden estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Submit comments on or before August 30, 2004.

FOR FURTHER INFORMATION CONTACT: Beverly Johnson, Bureau for Management, Office of Administrative Services, Information and Records Division, U.S. Agency for International Development, Room 2.07–106, RRB, Washington, DC, 20523, (202) 712–1365 or via e-mail *bjohnson@usaid.gov*.

SUPPLEMENTARY INFORMATION:

OMB No.: OMB 0412–0020.

Form No.: AID 1450–4.

Title: Supplier's Certificate and Agreement with the U.S. Agency for International Development for Project Commodities/Invoice and Contract Abstract.

Type of Review: Renewal of Information Collection.

Purpose: When USAID is not a party to a contract which it finances, it needs some means of collecting information directly from the suppliers of such commodities and related services to enable it to take appropriate action in the event that they do not comply with applicable USAID regulations. The information collection, recordkeeping, and reporting requirements are necessary to assure that USAID funds are expended in accordance with statutory requirements and USAID policies. It also allows for positive identification of transactions where overcharges occur.

Annual Reporting Burden:

Respondents: 60.

Total annual responses: 360.

Total annual hours requested: 231 hours.

Dated: June 22, 2004.

Joanne Paskar,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 04–14691 Filed 6–28–04; 8:45 am]

BILLING CODE 6116–01–M

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collections Being Reviewed by the U.S. Agency for International Development; Comments Requested

SUMMARY: U.S. Agency for International Development (USAID) is making efforts to reduce the paperwork burden. USAID invites the general public and other Federal agencies to take this opportunity to comment on the following proposed and/or continuing information collections, as required by the Paperwork Reduction Act for 1995. Comments are requested concerning: (a) Whether the proposed or continuing collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the burden estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Submit comments on or before August 30, 2004.

FOR FURTHER INFORMATION CONTACT: Beverly Johnson, Bureau for Management, Office of Administrative Services, Information and Records Division, U.S. Agency for International Development, Room 2.07–106, RRB, Washington, DC 20523, (202) 712–1365 or via e-mail *bjohnson@usaid.gov*.

SUPPLEMENTARY INFORMATION:

OMB No.: OMB 0412–0520.

Form No.: AID 1420–17.

Title: Information Collection Elements in the USAID Acquisition Regulation (AIDAR), 48 Chapter 7.

Type of Review: Renewal of Information Collection.

Purpose: USAID is authorized to make contracts with any corporation, international organization, or other body of persons in or outside of the United States in furtherance of the purposes and within limitations of the Foreign Assistance Act (FAA). The information collections requirements placed on the public are published in 48 CFR chapter 7, and include such items as the Contractor Employee Biographical Data Sheet and Performance and Progress Reports (AIDAR 752.7026). These are all USAID unique procurement requirements. The pre-award requirements are based on a need for prudent management in the determination that an offeror either has or can obtain the ability to competently manage development assistance programs utilizing public funds. The requirements for information collection requirements during the post-award period are based on the need to administer public funds prudently.

Annual Reporting Burden:

Respondents: 6,300.

Total annual responses: 53,270.

Total annual hours requested: 74,620 hours.

Dated: June 22, 2004.

Joanne Paskar,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 04–14692 Filed 6–28–04; 8:45 am]

BILLING CODE 6116–01–M

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collections Being Reviewed by the U.S. Agency for International Development; Comments Requested

SUMMARY: U.S. Agency for International Development (USAID) is making efforts to reduce the paperwork burden. USAID invites the general public and other Federal agencies to take this opportunity to comment on the following proposed and/or continuing information collections, as required by the Paperwork Reduction Act for 1995. Comments are requested concerning: (a) Whether the proposed or continuing collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the burden estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Submit comments on or before August 30, 2004.

FOR FURTHER INFORMATION CONTACT: Beverly Johnson, Bureau for Management, Office of Administrative Services, Information and Records Division, U.S. Agency for International Development, Room 2.07–106, RRB Washington, DC 20523, (202) 712–1365 or via e-mail *bjohnson@usaid.gov*.

SUPPLEMENTARY INFORMATION:

OMB No.: OMB 0412–0543.

Form Nos.: AID 1558–1A.

Title: Financial Status Report (Form 268 and 269 worksheet).

Type of Review: Renewal of Information Collection.

Purpose: The purpose of this information collection is to assure that ASHA grant recipients are accountable for expenditures incurred under the grant agreement for only those items authorized by the agreement. The information is used by ASHA to monitor the expenditures under each authorized line item and calculate the monetary gain or loss realized during the life of the grant.

Annual Reporting Burden:

Respondents: 196.

Total annual responses: 760.

Total annual hours requested: 5,320 hours.

Dated: June 22, 2004.

Joanne Paskar,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 04–14693 Filed 6–28–04; 8:45 am]

BILLING CODE 6116–01–M

AGENCY FOR INTERNATIONAL DEVELOPMENT

Notice of Public Information Collections Being Reviewed by the U.S. Agency for International Development; Comments Requested

SUMMARY: U.S. Agency for International Development (USAID) is making efforts to reduce the paperwork burden. USAID invites the general public and other Federal agencies to take this opportunity to comment on the following proposed and/or continuing information collections, as required by the Paperwork Reduction Act for 1995. Comments are requested concerning: (a) Whether the proposed or continuing collections of information are necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the burden estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology.

DATES: Submit comments on or before August 30, 2004.

FOR FURTHER INFORMATION CONTACT: Beverly Johnson, Bureau for Management, Office of Administrative Services, Information and Records Division, U.S. Agency for International Development, Room 2.07–106, RRB, Washington, DC 20523, (202) 712–1365 or via e-mail *bjohnson@usaid.gov.*

SUPPLEMENTARY INFORMATION:

OMB No.: OMB 0412–0542.

Form No.: Aid 1558–2.

Title: Request for Advance or Reimbursement.

Type of Review: Renewal of Information Collection.

Purpose: The purpose of this information collection is to assure that American Schools and Hospitals Abroad (ASHA) grant recipients are permitted to obtain advances or reimbursements for expenditures that are authorized by the grant agreement. The information is used by (a) ASHA to monitor grant implementation relative to financial matters, (b) the Office of Financial Management (FM) to track disbursements and expenditures, and (c) the Department of the Treasury to effect payments.

Annual Reporting Burden:

Respondents: 196.

Total annual responses: 1,140.

Total annual hours requested: 2,280 hours.

Dated: June 22, 2004.

Joanne Paskar,

Chief, Information and Records Division, Office of Administrative Services, Bureau for Management.

[FR Doc. 04–14694 Filed 6–28–04; 8:45 am]

BILLING CODE 6116–01–M

ANTITRUST MODERNIZATION COMMISSION

Public Meeting

AGENCY: Antitrust Modernization Commission.

ACTION: Notice of public meeting.

SUMMARY: The Antitrust Modernization Commission will hold a public meeting on July 15, 2004. The purpose of the meeting will be to discuss and adopt the process by which the Commission will identify issues to study in fulfilling its statutory duties. The Executive Director will also report to the Commission on administrative matters.

DATES: July 15, 2004, 3 p.m. until 5 p.m., unless earlier adjourned. All interested members of the public may attend. Registration is not required. There will be a brief period for questions from the public at the conclusion of the meeting.

ADDRESSES: Rayburn House Office Building, Room 2226, located at the corner of Independence Avenue and South Capitol Street, SW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Andrew J. Heimert, Executive Director & General Counsel, Antitrust Modernization Commission: telephone: (202) 326–2487; e-mail: *info@amc.gov.* Mr. Heimert is also the Designated Federal Officer (DFO) for the Antitrust Modernization Commission.

SUPPLEMENTARY INFORMATION: The Antitrust Modernization Commission ("AMC" or "Commission") was established by the Antitrust Modernization Commission Act of 2002. Public Law 107–273, sections 11051–60, 116 Stat. 1758, 1856–59. The duties of the Commission are:

(1) To examine whether the need exists to modernize the antitrust laws and to identify and study related issues;

(2) To solicit views of all parties concerned with the operation of the antitrust laws;

(3) To evaluate the advisability of proposals and current arrangements with respect to any issues so identified; and

(4) To prepare and submit to Congress and the President a report.

Id. section 11053. The Commission's report, which shall be issued no later than three years after the first meeting of the Commission, is to "contain[] a detailed statement of the findings and conclusions of the Commission, together with recommendation for legislative or administrative action the Commission considers to be appropriate." *Id.* section 11058.

The AMC has called this meeting pursuant to its authorizing statute and the Federal Advisory Committee Act. Antitrust Modernization Commission Act of 2002, Public Law 107–273, section 11058(f), 116 Stat. 1758, 1857; Federal Advisory Committee Act, 5 U.S.C. App., § 10(a)(2); 41 CFR 102–3.150 (2003).

Dated: June 24, 2004.

By direction of Deborah A. Garza, Chair of the Antitrust Modernization Commission.

Approved by Designated Federal Officer.

Andrew J. Heimert,

Executive Director & General Counsel, Antitrust Modernization Commission.

[FR Doc. 04–14695 Filed 6–28–04; 8:45 am]

BILLING CODE 6820–YM–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–560–803]

Antidumping Order on Extruded Rubber Thread From Indonesia: Revocation of Order

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

ACTION: Notice of Revocation of the Antidumping Duty Order of Extruded Rubber Thread from Indonesia.

SUMMARY: On April 1, 2004, the Department of Commerce ("the Department") initiated a sunset review of the antidumping duty order on Extruded Rubber Thread from Indonesia (69 FR 17129). Because the domestic interested parties did not participate in this sunset review, the Department is revoking this antidumping duty order.

DATES: *Effective Date:* May 21, 2004.

FOR FURTHER INFORMATION CONTACT: Hilary Sadler, Esq., Office of Policy, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington, DC 20230; telephone: (202) 482–4340.

SUPPLEMENTARY INFORMATION:

The Applicable Statue

The Department's procedures for the conduct of sunset reviews are set forth in Section 751(c) of the Tariff Act of 1930, as amended (the "Act"), and 19 CFR 351.218. Guidance on methodological and analytical issues relevant to the Department's conduct of sunset reviews is set forth in the Department's Policy Bulletin 98:3—*Policies regarding the Conduct of Five-Year Sunset Reviews of Antidumping and Countervailing Duty Orders: Policy Bulletin*, 63 FR 18871 (April 16, 1998) ("*Sunset Policy Bulletin*").

For purposes of this review, the product covered is extruded rubber thread ("ERT") from Indonesia. ERT is defined as vulcanized rubber thread obtained by extrusion of stable or concentrated natural rubber latex of any cross sectional shape, measuring from 0.18 mm, which is 0.007 inches or 140 gauge, to 1.42 mm, which is 0.056 inch or 18 gauge, in diameter. ERT is currently classified under subheadings 4007.00.00 of the Harmonized Tariff Schedule ("HTS"). Although the HTS subheadings are provided for convenience and customs purposes, the written description of the scope of this order is dispositive.

Background

On May 21, 1999, the Department issued an antidumping duty order on ERT (64 FR 27755). Pursuant to section 751(c) of the Act and 19 CFR part 351, the Department initiated a sunset review of this order by publishing notice of the initiation in the **Federal Register** 69 FR 17129 (April 1, 2004). In addition, as a courtesy to interested parties, the Department sent letters, via certified and registered mail, to each party listed on the Department's most current service list for this proceeding to inform them of the automatic initiation of a sunset review of this order.

We received no response from the domestic industry by the deadline dates (*see* 19 CFR 351.218(d)(1)(i)). As a result, the Department determined that no domestic party intends to participate in the sunset review, and on April 20, 2004, we notified the International Trade Commission that we intended to issue a final determination revoking this antidumping duty order.

Determination To Revoke

Pursuant to section 751(c)(3)(A) of the Act and 19 CFR 351.218(d)(1)(iii)(B)(*3*), if no domestic interested party responds to the notice of initiation, the Department shall issue a final determination, within 90 days after the initiation of the review, revoking the order. Because no domestic interested party filed a notice of intent or substantive response, the Department finds that no domestic interested party is participating in this review, and we are revoking this antidumping duty order effective May 21, 2004, the fifth anniversary of the date of publication in the **Federal Register** of the order, consistent with 19 CFR 351.222(i)(2)(i).

Effective Date of Revocation

Pursuant to sections 751(c)(3)(A) and 751(d)(2) of the Act, and 19 CFR 351.222(i)(2)(i), the Department will instruct the Customs Service to terminate the suspension of liquidation of the merchandise subject to this order entered, or withdrawn from warehouse, on or after May 21, 2004. Entries of subject merchandise prior to the effective date of revocation will continue to be subject to suspension of liquidation and countervailing duty deposit requirements. The Department will complete any pending administrative reviews of this order and will conduct administrative reviews of subject merchandise entered prior to the effective date of revocation in response to appropriately filed requests for review.

This five-year ("sunset") review and notice are in accordance with sections 751(c), 752, and 777(i)(1) of the Act.

Dated: June 23, 2004

James J. Jochum,

Assistant Secretary for Import Administration.

[FR Doc. 04–14707 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–803]

Heavy Forged Hand Tools, Finished or Unfinished, With or Without Handles, From the People's Republic of China: Extension of Time Limit for Final Results of Antidumping Duty Administrative Reviews on Axes/Adzes, Bars/Wedges, Hammers/Sledges, and Picks/Mattocks

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

ACTION: Notice of Extension of Time Limit of Final Results of Administrative Reviews.

SUMMARY: The Department of Commerce (the Department) is extending the time limit for the final results of the administrative reviews of the antidumping duty orders on axes and adzes, bars and wedges, hammers and sledges, and picks and mattocks from the People's Republic of China (PRC) until September 7, 2004. This extension is made pursuant to section 751(a)(3)(A) of the Tariff Act of 1930, as amended, (the Act).

DATES: *Effective Date:* June 29, 2004.

FOR FURTHER INFORMATION CONTACT: Thomas Martin at (202) 482–3936; Office of AD/CVD Enforcement, Office 4, Group II, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Ave, NW., Washington, DC 20230.

SUPPLEMENTARY INFORMATION:

Background

On March 25, 2003, the Department published a notice of initiation of administrative reviews of the antidumping duty orders on heavy forged hand tools (HFHTs) from the PRC, covering the period February 1, 2002, through January 31, 2003. *See Initiation of Antidumping and Countervailing Duty Administrative Reviews and Requests for Revocation in Part*, 68 FR 14394 (March 25, 2003). The deadline for the preliminary results of these administrative reviews was extended on October 16, 2003. *See Heavy Forged Hand Tools, Finished or Unfinished, With or Without Handles, From the People's Republic of China: Extension of Time Limit for Preliminary Results of Antidumping Duty Administrative Review*, 68 FR 59583 (October 16, 2003). The Department published the preliminary results of these administrative reviews on March

10, 2004. *See Heavy Forged Hand Tools, Finished or Unfinished, With or Without Handles, From the People's Republic of China: Preliminary Results of Administrative Reviews, Preliminary Partial Rescission of Antidumping Duty Administrative Reviews, and Determination Not To Revoke in Part*, 69 FR 11371 (March 10, 2004).

Extension of Time Limits for Final Results of Reviews

Currently, the final results of administrative reviews are due on July 8, 2004. Section 751(a)(3)(A) of the Act requires the Department to complete its final results of review within 120 days after the date on which the preliminary results were published. However, the Department may extend the deadline for completion of an administrative review if it determines that it is not practicable to complete the review within the statutory time limit. Section 751(a)(3)(A) of the Act allows the Department to extend the deadline for completion of the final results to 180 days from the date of publication of the preliminary results. As a result of the complex issues involved in this review, the Department has determined that it is not practicable to complete these reviews within the original time limit. For this reason, we are extending the time limit by sixty days, to September 7, 2004. *See* Memorandum from Holly Kuga, Office Director, to Jeff May, Deputy Assistant Secretary for Import Administration, Group I, dated concurrently with this notice, which is on file in the Central Records Unit, Room B–099 of the main Commerce building.

This notice is published in accordance with section 735(a)(2) of the Act and 19 CFR 351.210(g).

Dated: June 23, 2004.

Jeffrey May,

Deputy Assistant Secretary for Import Administration, Group I.

[FR Doc. 04–14708 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–588–810]

Mechanical Transfer Presses From Japan: Extension of Time Limit for Final Results of Antidumping Administrative Review

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

SUMMARY: The Department of Commerce is extending the time limit for the final results of the administrative review of mechanical transfer presses (MTPs) from Japan until no later than July 14, 2004. The period of review is February 1, 2002 through January 31, 2003. This extension is made pursuant to section 751(a)(3)(A) of the Tariff Act of 1930, as amended (the Act).

DATES: *Effective Date:* June 29, 2004.

FOR FURTHER INFORMATION CONTACT: Jacqueline Arrowsmith, Office of AD/CVD Enforcement VII, Import Administration, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue, NW., Washington DC 20230; telephone: (202) 482–5255.

Background

On February 16, 1990, the Department issued an antidumping duty order on mechanical transfer presses from Japan. *See Antidumping Duty Order: Mechanical Transfer Presses from Japan*, 55 FR 5642 (February 16, 1990). The term "mechanical transfer presses" refers to automatic metal-forming machine tools with multiple die stations in which the work piece is moved from station to station by a transfer mechanism designed as an integral part of the press and synchronized with the press action, whether imported as machines or parts suitable for use solely or principally with these machines. These presses may be imported assembled or unassembled. *See Mechanical Transfer Presses From Japan: Final Results of Antidumping Administrative Review* 68 FR 39515.

On February 24, 2003, the Department of Commerce (the Department) received a timely request for administrative review of the antidumping duty order on MTPs from Japan from respondent Hitachi Zosen Corporation (HZC), and its subsidiary Hitachi Zosen Fukui Corporation d/b/a H&F Corporation (H&F). On February 27, 2003, the Department received a timely request from petitioner, IHI—Verson Press Technology, LLC for an administrative review of HZC and H&F. On February 28, 2003, HZC and H&F submitted a timely request that the Department revoke the order with respect to HZC and H&F based on the absence of dumping in three consecutive reviews, in accordance with section 351.222(e) of the Department's regulations. On March 25, 2003, the Department published a notice of initiation of this administrative review, covering the period of February 1, 2002 through January 31, 2003 (*see* 68 FR 14394), for HZC and its subsidiary H&F. On October 15, 2003, the Department published the *Mechanical Transfer Presses from Japan: Extension of Time Limit for Preliminary Results of Antidumping Administrative Review*, 68 FR 59365, in which we extended the preliminary results until not later than February 28, 2004.

On March 8, 2004, the Department published the *Preliminary Results of Antidumping Duty Administrative Review and Preliminary Determination Not to Revoke, in-Part: Mechanical Transfer Presses from Japan*, 69 FR 10675 (Preliminary Results). The final results of this administrative review are currently due not later than July 6, 2004.

Extension of Time Limits for the Final Results

HZC/H&F has requested revocation with respect to the order. There are complex issues with regard to the issue of revocation. Therefore, it is not practicable to complete this review within the time limits mandated by section 751(a)(3)(A) of the Act. The Department is therefore extending the time period for issuing the preliminary results of this review from July 6, 2004, until no later than July 14, 2004, in accordance with section 751(a)(3)(A) of the Act: This notice is published pursuant to sections 751(a)(3)(A) and 777(I)(1) of the Act.

Dated: June 18, 2004.

James J. Jochum,

Assistant Secretary for Import Administration.

[FR Doc. 04–14709 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–DS–P

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Adjustment of Import Limits for Certain Cotton, Wool, and Man-Made Fiber Textile Products Produced or Manufactured in Hong Kong

June 24, 2004.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner, Bureau of Customs and Border Protection adjusting limits.

EFFECTIVE DATE: June 30, 2004.

FOR FURTHER INFORMATION CONTACT: Naomi Freeman, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482–4212. For information on the quota status of these limits, refer to the Quota Status Reports posted on the bulletin boards of each Customs port, call (202) 927–5850, or refer to the Bureau of Customs and Border

Protection website at http://www.cbp.gov. For information on embargoes and quota re-openings, refer to the Office of Textiles and Apparel website at http://otexa.ita.doc.gov.

SUPPLEMENTARY INFORMATION:

Authority: Section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854); Executive Order 11651 of March 3, 1972, as amended.

The current limits for certain categories are being adjusted for carryforward used and carryover.

A description of the textile and apparel categories in terms of HTS numbers is available in the CORRELATION: Textile and Apparel Categories with the Harmonized Tariff Schedule of the United States (see **Federal Register** notice 69 FR 4926, published on February 2, 2004). Also see 68 FR 59917, published on October 20, 2003.

D. Michael Hutchinson,

Acting Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

June 24, 2004.

Commissioner,

Bureau of Customs and Border Protection, Washington, DC 20229.

Dear Commissioner: This directive amends, but does not cancel, the directive issued to you on October 14, 2003, by the Chairman, Committee for the Implementation of Textile Agreements. That directive concerns imports of certain cotton, wool, man-made fiber, silk blend and other vegetable fiber textiles and textile products, produced or manufactured in Hong Kong and exported during the twelve-month period which began on January 1, 2004 and extends through December 31, 2004.

Effective on June 30, 2004, you are directed to adjust the limits for the following categories, as provided for under the Uruguay Round Agreement on Textiles and Clothing:

Category	Adjusted twelve-month limit [1]
Sublevels in Group II	
331pt.	1,625,282 dozen pairs.
335	353,909 dozen.
338/339 [2] (shirts and blouses other than tank tops and tops, knit).	3,020,630 dozen.
338/339(1) [3] (tank tops and knit tops).	2,269,414 dozen.
340	2,892,570 dozen.
345	528,377 dozen.
347/348	7,004,097 dozen of which not more than 6,914,097 dozen shall be in Categories 347–W/348–W [4]; and not more than 5,239,765 dozen shall be in Category 348–W.
445/446	1,387,918 dozen.
638/639	5,071,011 dozen.
641	876,249 dozen.
648	1,194,260 dozen of which not more than 1,194,260 dozen shall be in Category 648–W [5].
Within Group II Subgroup	
342	645,873 dozen.

[1] The limits have not been adjusted to account for any imports exported after December 31, 2003.

[2] Categories 338/339: all HTS numbers except 6109.10.0018, 6109.10.0023, 6109.10.0060, 6109.10.0065, 6114.20.0005 and 6114.20.0010.

[3] Category 338/339(1): only HTS numbers 6109.10.0018, 6109.10.0023, 6109.10.0060, 6109.10.0065, 6114.20.0005 and 6114.20.0010.

[4] Category 347–W: only HTS numbers 6203.19.1020, 6203.19.9020, 6203.22.3020, 6203.22.3030, 6203.42.4005, 6203.42.4010, 6203.42.4015, 6203.42.4025, 6203.42.4035, 6203.42.4045, 6203.42.4050, 6203.42.4060, 6203.49.8020, 6210.40.9033, 6211.20.1520, 6211.20.3810 and 6211.32.0040; Category 348–W: only HTS numbers 6204.12.0030, 6204.19.8030, 6204.22.3040, 6204.22.3050, 6204.29.4034, 6204.62.3000, 6204.62.4005, 6204.62.4010, 6204.62.4020, 6204.62.4030, 6204.62.4040, 6204.62.4050, 6204.62.4055, 6204.62.4065, 6204.69.6010, 6204.69.9010, 6210.50.9060, 6211.20.1550, 6211.20.6810, 6211.42.0030 and 6217.90.9050.

[5] Category 648–W: only HTS numbers 6204.23.0040, 6204.23.0045, 6204.29.2020, 6204.29.2025, 6204.29.4038, 6204.63.2000, 6204.63.3000, 6204.63.3510, 6204.63.3530, 6204.63.3532, 6204.63.3540, 6204.69.2510, 6204.69.2530, 6204.69.2540, 6204.69.2560, 6204.69.6030, 6204.69.9030, 6210.50.5035, 6211.20.1555, 6211.20.6820, 6211.43.0040 and 6217.90.9060.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception to the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

D. Michael Hutchinson,

Acting Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 04–14710 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–DR–S

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Adjustment of Import Limits for Certain Cotton and Man-Made Fiber Textiles and Textile Products Produced or Manufactured in India

June 23, 2004.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner, Bureau of Customs and Border Protection adjusting limits.

EFFECTIVE DATE: June 30, 2004.

FOR FURTHER INFORMATION CONTACT: Ross Arnold, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482–4212. For information on the quota status of these limits, refer to the Quota Status Reports posted on the bulletin boards of each Customs port, call (202) 927–5850, or refer to the Bureau of Customs and Border Protection website at http://www.cbp.gov. For information on embargoes and quota re-openings, refer to the Office of Textiles and Apparel website at http://otexa.ita.doc.gov.

SUPPLEMENTARY INFORMATION:

Authority: Section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854); Executive Order 11651 of March 3, 1972, as amended.

The current limits for certain categories are being adjusted for carryover, the recrediting of unused carryforward, swing, and special shift.

A description of the textile and apparel categories in terms of HTS numbers is available in the CORRELATION: Textile and Apparel Categories with the Harmonized Tariff Schedule of the United States (see **Federal Register** notice 69 FR 4926, published on February 2, 2004). Also see 68 FR 65253, published on November 19, 2003.

D. Michael Hutchinson,

Acting Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

June 23, 2004.

Commissioner,

Bureau of Customs and Border Protection, Washington, DC 20229

Dear Commissioner: This directive amends, but does not cancel, the directive issued to you on November 13, 2003, by the Chairman, Committee for the Implementation of Textile Agreements. That directive concerns imports of certain cotton, man-made fiber, silk blend and other vegetable fiber textiles and textile products, produced or manufactured in India and exported during the twelve-month period which began on January 1, 2004 and extends through December 31, 2004.

Effective on June 30, 2004, you are directed to adjust the current limits for the following categories, as provided for under the Uruguay Round Agreement on Textiles and Clothing:

Category	Adjusted twelve-month limit [1]
Levels in Group I	
218	30,535,871 square meters.
219	129,361,849 square meters.
313	81,702,686 square meters.
314	15,400,220 square meters.
315	25,866,199 square meters.
317	37,260,024 square meters.
326	14,791,782 square meters.
334/634	274,420 dozen.
335/635	1,302,773 dozen.
336/636	1,846,508 dozen.
338/339	6,001,600 dozen.
340/640	3,301,706 dozen.
341	6,817,840 dozen of which not more than 3,904,760 dozen shall be in Category 341–Y [2].
342/642	2,638,120 dozen.
345	433,969 dozen.
347/348	1,417,662 dozen.
351/651	505,663 dozen.
363	83,619,522 numbers.
641	2,761,543 dozen.
647/648	1,452,789 dozen.

[1] The limits have not been adjusted to account for any imports exported after December 31, 2003.

[2] Category 341–Y: only HTS numbers 6204.22.3060, 6206.30.3010, 6206.30.3030 and 6211.42.0054.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception to the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

D. Michael Hutchinson,

Acting Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 04–14711 Filed 6–28–04; 8:45 am]

BILLING CODE 3510–DR–S

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Information Collection; Submission for OMB Review; Comment Request

AGENCY: Corporation for National and Community Service.

ACTION: Notice.

SUMMARY: The Corporation for National and Community Service (hereinafter the "Corporation") has submitted a public information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995, Public Law 104–13, (44 U.S.C. chapter 35). Copies of this ICR, with applicable supporting documentation, may be obtained by calling the Corporation for National and Community Service, Ms. Angela Roberts, at (202) 606–5000, extension 111, (*aroberts@cns.gov*); (TTY/TDD) at (202) 606–5256 between the hours of 9 a.m. and 4 p.m. eastern standard time, Monday through Friday.

DATES: Comments may be submitted, identified by the title of the information collection activity, by any of the following two methods listed in the address section, within 30 days from the date of publication in this **Federal Register**.

ADDRESSES: Comments may be submitted, identified by the title of the information collection activity, by any of the following two methods:

(1) By fax to: (202) 395–6974, Attention: Ms. Katherine Astrich, OMB Desk Officer for the Corporation for National and Community Service; and

(2) Electronically by e-mail to: *Katherine_T._Astrich@omb.eop.gov*.

SUPPLEMENTARY INFORMATION: The OMB is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Corporation, including whether the information will have practical utility;
- Evaluate the accuracy of the Corporation's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Propose ways to enhance the quality, utility and clarity of the information to be collected; and
- Propose ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.*, permitting electronic submissions of responses.

Type of Review: Request for reinstatement, with change, of a previously approved collection for which approval has expired.

Agency: Corporation for National and Community Service.

Title: National Senior Services Corps Project Progress Report.

OMB Number: 3045–0033.

Agency Number: CNCS Form 1020.

Affected Public: Sponsors of National Senior Service Corps grants.

Total Respondents: 1,350.

Frequency: Semi-annual. It is estimated that 1,350 will respond semi-annually and 50 quarterly.

Average Time Per Respondent:
8.7 hours reporting semi-annually.
14.7 hours reporting quarterly.

Estimated Total Burden Hours: 12,045.

Total Burden Cost (capital/startup): None.

Total Burden Cost (operating/maintenance): $2,000.

Description: The Corporation requests reinstatement, with changes, of its National Senior Service Corps Project Progress Report which reflects the Corporation's intention to modify selected sections of the collection instrument to reflect changes in data considered "core reporting" information to meet a variety of needs, including:

- Modification of data elements, including adding new data elements as needed to ensure information collection captures appropriate data for the Corporation's required performance measurement and other reporting.

The Project Progress Report (PPR) was designed to assure that National Service Corps (NSSC) grantees address and fulfill legislated program purposes, meet agency program management and grant requirements, and assess progress toward work plan objectives agreed upon in the granting of the award.

Further, the reinstatement of the previously used PPR will: (a) Enhance data elements collected via this information collection tool; (b) migrate the paper version of the form to the Corporation's electronic grants management system, eGrants; and (c) establish reporting periods consistent with the Corporation's integrated grants management and reporting policies.

Comments: A 60-day public comment notice, regarding modification of the Project Progress Report was published in the **Federal Register** on December 5, 2003. This comment period ended on February 5, 2004; no comments were received.

Dated: June 22, 2004.

Tess Scannell,

Director, National Senior Service Corps.

[FR Doc. 04–14715 Filed 6–28–04; 8:45 am]

BILLING CODE 6050–$$–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Submission for OMB Review; Comment Request

ACTION: Notice.

The Department of Defense has submitted to OMB for clearance, the following proposal for collection of information under the provisions of the

Paperwork Reduction Act (44 U.S.C. Chapter 35).

DATES: Consideration will be given to all comments received by July 29, 2004.

Title, Forms, and OMB Number: Dependency Statements: Parent, Child Born Out of Wedlock, Incapacitated Child Over Age 21, Full Time Student 21–22 Years of Age, and Ward of a Court; DD Forms 137–3, 137–4, 137–5, 137–6, 137–7, OMB Number 0730–0014.

Type of Request: Reinstatement.

Number of Respondents: 19,440.

Responses Per Respondent: 1.

Annual Responses: 19,440.

Average Burden Per Response: 1.25 hours.

Annual Burden Hours: 24,300.

Needs and Uses: This information collection is used to certify dependency or obtain information to determine entitlement to basic allowance for housing with dependent rate, travel allowance, or Uniformed Services Identification and Privilege Card. Information regarding the particular dependent situation is provided by the military member or by another individual who may be a member of the public. DoDFMR 7000.14, Vol.7A defines dependency and directs that dependency be proven. Dependency claim examiners use the information from the forms to determine the degree of benefits. The requirements to provide the information decreases the possibility of monetary allowances being approved on behalf of ineligible dependents.

Affected Public: Individuals or households.

Frequency: On occasion and annually.

Respondent's Obligation: Required to obtain or retain benefits.

OMB Desk Officer: Ms. Jacqueline Zeiher.

Written comments and recommendations on the proposed information collection should be sent to Ms. Zeiher at the Office of Management and Budget, Desk Officer for DoD, Room 10236, New Executive Office Building, Washington, DC 20503.

DOD Clearance Officer: Mr. Rober Cushing.

Written requests for copies of the information collection proposal should be sent to Mr. Cushing, WHS/ESCD/Information Management Division, 1225 South Clark Street, Suite 504, Arlington, VA 22202–4326.

Dated: June 23, 2004.

L.M. Bynum,

Alternate OSD Federal Register, Liaison Officer, Department of Defense.

[FR Doc. 04–14648 Filed 6–28–04; 8:45 am]

BILLING CODE 5001–06–M

DEPARTMENT OF DEFENSE

Office of the Secretary

Defense Business Board; Notice of Advisory Committee Meeting

AGENCY: Department of Defense, DoD.

ACTION: Notice of advisory committee meeting.

SUMMARY: The Defense Business Board (DBB) will meet in open session on Thursday, July 15, 2004, at the Pentagon, Washington, DC from 0815 until 1000. The mission of the DBB is to advise the Senior Executive Council (SEC) and the Secretary of Defense on effective strategies for implementation of best business practices of interest to the Department of Defense. At this meeting, the Board's Acquisition, Human Resources, and Financial Management related task groups will deliberate on their preliminary, findings and recommendations related to tasks assigned earlier this year.

DATES: Thursday, July 15, 2004, 0815 to 1000 hrs.

FOR FURTHER INFORMATION CONTACT: Members of the public who wish to attend the meeting must contact the Defense Business Board no later than Thursday, July 8 for further information about admission as seating is limited. Additionally, those who wish to make oral comments or deliver written comments should also request to be scheduled, and submit a written text of the comments by Thursday, July 8 to allow time for distribution to the Board members prior to the meeting. Individual oral comments will be limited to five minutes, with the total oral comment period not exceeding thirty-minutes.

The DBB may be contacted at: Defense Business Board, 1100 Defense Pentagon, Room 2E314, Washington, DC 20301–1100, via e-mail at *DBB@osd.pentagon.mil,* or via phone at (703) 614–7085.

Dated: June 23, 2004.

L.M. Bynum,

Alternative OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 04–14649 Filed 6–28–04; 8:45 am]

BILLING CODE 5001–06–M

DEPARTMENT OF EDUCATION

Submission for OMB Review; Comment Request

AGENCY: Department of Education.

SUMMARY: The Leader, Regulatory Information Management Group, Office of the Chief Information Officer invites comments on the submission for OMB review as required by the Paperwork Reduction Act of 1995.

DATES: Interested persons are invited to submit comments on or before July 29, 2004.

ADDRESSES: Written comments should be addressed to the Office of Information and Regulatory Affairs, Attention: Carolyn Lovett, Desk Officer, Department of Education, Office of Management and Budget, 725 17th Street, N.W., Room 10235, New Executive Office Building, Washington, DC 20503 or faxed to (202) 395–6974.

SUPPLEMENTARY INFORMATION: Section 3506 of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35) requires that the Office of Management and Budget (OMB) provide interested Federal agencies and the public an early opportunity to comment on information collection requests. OMB may amend or waive the requirement for public consultation to the extent that public participation in the approval process would defeat the purpose of the information collection, violate State or Federal law, or substantially interfere with any agency's ability to perform its statutory obligations. The Leader, Regulatory Information Management Group, Office of the Chief Information Officer, publishes that notice containing proposed information collection requests prior to submission of these requests to OMB. Each proposed information collection, grouped by office, contains the following: (1) Type of review requested, *e.g.* new, revision, extension, existing or reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

Dated: June 22, 2004.

Angela C. Arrington,

Leader, Regulatory Information Management Group, Office of the Chief Information Officer.

Office of Vocational and Adult Education

Type of Review: New.

Title: Annual Performance Report Grants Under the Smaller Learning Communities Program.

Frequency: Annually.

Affected Public: State, local, or tribal gov't, SEAs or LEAs (primary).

Reporting and Recordkeeping Hour Burden:

Responses: 400.

Burden Hours: 4,000.

Abstract: The Annual Performance Report form requests information from grantees regarding progress made in achieving the objectives identified in the grantee's application including student outcome data and program implementation information.

Requests for copies of the submission for OMB review; comment request may be accessed from *http://edicsweb.ed.gov*, by selecting the "Browse Pending Collections" link and by clicking on link number 2548. When you access the information collection, click on "Download Attachments" to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., Potomac Center, 9th Floor, Washington, DC 20202–4700. Requests may also be electronically mailed to the Internet address *OCIO_RIMG@ed.gov* or faxed to 202–245–6621. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be directed to Sheila Carey at her e-mail address *Sheila.Carey@ed.gov*. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. 04–14653 Filed 6–28–04; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

Office of Postsecondary Education; Overview Information; Jacob K. Javits Fellowship Program

Notice inviting applications for new awards for fiscal year (FY) 2005.

Catalog of Federal Domestic Assistance (CFDA) Number: 84.170A.

Dates: Applications Available: August 11, 2004.

Deadline for Transmittal of Applications for the Jacob K. Javits Fellowship Program: October 8, 2004.

Deadline for Transmittal of the Free Application for Federal Student Aid (FAFSA): January 31, 2005.

Eligible Applicants: Individuals who at the time of application: (1) Have not completed their first full year of study for a doctoral degree or a master's degree in those fields in which the master's degree is the terminal highest degree awarded in the selected field of study, or will be entering a doctoral degree program or a master's degree program in those fields in which the master's degree is the terminal highest degree awarded in the selected field of study in academic year 2005–2006; (2) are eligible to receive grant, loan, or work assistance pursuant to section 484 of the Higher Education Act of 1965, as amended (HEA); and (3) intend to pursue a doctoral or master's degree in fields selected by the JKJ Fellowship Board at accredited U.S. institutions of higher education. An individual must be a citizen or national of the United States, a permanent resident of the United States, in the United States for other than a temporary purpose and intending to become a permanent resident, or a citizen of any one of the Freely Associated States.

Estimated Available Funds: $2,928,305.

Estimated Average Size of Awards: $41,511.

Estimated Number of Awards: 71.

Note: The Department is not bound by any estimates in this notice.

Project Period: Up to 48 months.

Full Text of Announcement

I. Funding Opportunity Description

Purpose of Program: The purpose of the Jacob K. Javits (JKJ) Fellowship Program is to award fellowships to eligible students of superior ability, selected on the basis of demonstrated achievement, financial need, and exceptional promise, to undertake graduate study in selected fields in the arts, humanities, and social sciences leading to a doctoral degree or to a master's degree in those fields in which the master's degree is the terminal highest degree awarded in the selected field of study at accredited institutions of higher education. The selected fields in the arts are: creative writing, music performance, music theory, music composition, music literature, studio arts (including photography), television, film, cinematography, theater arts, playwriting, screenwriting, acting, and dance. The selected fields in the humanities are: art history (including architectural history), archeology, area studies, classics, comparative literature, English language and literature, folklore, folk life, foreign languages and literature, history, linguistics, philosophy, religion (excluding study of religious vocation), speech, rhetoric, and debate. The selected fields in the social sciences are: anthropology, communications and media, economics, ethnic and cultural studies, geography, political science, psychology (excluding clinical psychology), public policy and public administration, and sociology (excluding the master's and doctoral degrees in social work).

Program Authority: 20 U.S.C. 1134–1134d.

Applicable Regulations: (a) The Education Department General Administrative Regulations (EDGAR) in 34 CFR parts 74, 75 (except as provided in 34 CFR 650.3(b)), 77, 82, 84, 85, 86, 97, 98 and 99; and (b) The regulations for this program in 34 CFR part 650.

II. Award Information

Type of Award: Discretionary grant.

Estimated Available Funds: $2,928,305.

Estimated Average Size of Awards: $41,511.

Estimated Number of Awards: 71.

Note: The Department is not bound by any estimates in this notice.

Project Period: Up to 48 months.

III. Eligibility Information

1. *Eligible Applicants:* Individuals who at the time of application: (1) Have not completed their first full year of study for a doctoral degree or a master's degree in those fields in which the master's degree is the terminal highest degree awarded in the selected field of study, or will be entering a doctoral degree program or a master's degree program in those fields in which the master's degree is the terminal highest degree awarded in the selected field of study in academic year 2005–2006; (2) are eligible to receive grant, loan, or work assistance pursuant to section 484 of the HEA; and (3) intend to pursue a doctoral or master's degree in fields selected by the JKJ Fellowship Board at accredited U.S. institutions of higher education. An individual must be a citizen or national of the United States, a permanent resident of the United States, in the United States for other than a temporary purpose and intending to become a permanent resident, or a citizen of any one of the Freely Associated States.

2. *Cost Sharing or Matching:* There are no cost sharing or matching requirements for this program.

IV. Application and Submission Information

1. *Address to Request Application Package:* Education Publications Center (ED Pubs), P.O. Box 1398, Jessup, MD 20794–1398. Telephone (toll free): 1–877–433–7827. FAX: (301) 470–1244. If you use a telecommunications device for the deaf (TDD), you may call (toll free): 1–877–576–7734.

You may also contact ED Pubs at its Web site: *www.ed.gov/edpubs.html* or you may contact ED Pubs at its e-mail address: *edpubs@inet.ed.gov*.

The application may also be accessed on the JKJ Fellowship Program Web site: *http://www.ed.gov/programs/iegpsjavits/index.html*.

Note: The FAFSA may be obtained from the institution of higher education's financial aid office or accessed at: *www.fafsa.ed.gov.*

If you request an application from ED Pubs, be sure to identify this competition as follows: CFDA number 84.170A.

Individuals with disabilities may obtain a copy of the application package in an alternative format (*e.g.*, Braille, large print, audiotape, or computer diskette) by contacting the program contact person listed under **FOR FURTHER INFORMATION CONTACT** in section VII of this notice.

2. *Content and Form of Application Submission:* Requirements concerning the content of an application, together with the forms you must submit, are in the application package for this program.

3. *Submission Dates and Times:*

Applications Available: August 11, 2004.

Deadline for Transmittal of Applications for the JKJ Fellowship Program: October 8, 2004.

Deadline for Transmittal of the FAFSA: January 31, 2005.

The dates and times for the transmittal of applications by mail or by hand (including a courier service or commercial carrier) are in the application package for this program.

We do not consider an application that does not comply with the deadline requirements.

4. *Intergovernmental Review:* This program is not subject to Executive Order 12372 and the regulations in 34 CFR part 79.

5. *Funding Restrictions:* We reference regulations outlining funding restrictions in the *Applicable Regulations* section of this notice.

6. *Other Submission Requirements:* Instructions and requirements for the transmittal of applications by mail or by hand (including a courier service or commercial carrier) are in the application package for this program.

V. Application Review Information

1. *Selection Criteria:* The selection criteria for this program have been established by the Jacob K. Javits Program Fellowship Board, pursuant to section 702(a)(2) of the HEA and 34 CFR 650.20(a). The selection criteria for applications in the humanities and social sciences are: (a) Statement of purpose (100 points); (b) letters of recommendation (100 points); (c) academic record (150 points); and (d) scholarly awards/honors (50 points). The selection criteria for applications in the arts are: (a) Statement of purpose (100 points); (b) letters of recommendation (100 points); (c) academic record (50 points); (d) scholarly awards/honors (50 points); and (e) supporting arts materials (100 points).

2. *Review and Selection Process:* The review and selection process for the JKJ Fellowship Program consists of a two-part process. Eligible applications are read and rated by a distinguished panel of scholars and academics in each of fields of the arts, humanities, and social sciences on the basis of demonstrated scholarly achievements and exceptional promise. The second part of the evaluation is a determination of financial need.

VI. Award Administration Information

1. *Award Notices:* Successful applicants will be notified by telephone and a Grant Award Notification (GAN) will be sent directly to the institution the applicant will be attending. Unsuccessful applicants will be notified.

2. *Administrative and National Policy Requirements:* We identify administrative and national policy requirements in the application package and reference these and other requirements in the *Applicable Regulations* section of this notice.

We reference the regulations outlining the terms and conditions of an award in the *Applicable Regulations* section of this notice and include these and other specific conditions in the GAN.

3. *Reporting:* On an annual basis, fellows are required to submit their Student Aid Report to the Javits Program Coordinator at their institution as specified by the Secretary in 34 CFR 650.37.

4. *Performance Measures:* The effectiveness of the JKJ Fellowship Program will be measured by graduate completion rates, time to degree completion rates, and the costs per PhD of talented graduate students, with demonstrated financial need, who are pursuing the highest degree available in their designated fields of study. Institutions of higher education in which the fellows are enrolled are required to submit an annual report documenting the fellows' satisfactory academic progress and the determined financial need. The Department will use the reports to assess the program's success in assisting fellows in completing their course of study and receiving their degree.

VII. Agency Contacts

For Further Information Contact: Gary Thomas or Carmen Gordon, Jacob K. Javits Fellowship Program, U.S. Department of Education, Teacher and Student Development Service, 1990 K St., NW., suite 6000, Washington, DC 20006–8524. Telephone: (202) 502–7542 or via Internet: *ope_javits_program@ed.gov.*

If you use a telecommunications device for the deaf (TDD), you may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

Individuals with disabilities may obtain this document in an alternative format (*e.g.*, Braille, large print, audiotape, or computer diskette) on request to the program contact persons listed in this section.

VIII. Other Information

Electronic Access to This Document: You may view this document, as well as all other documents of this Department published in the **Federal Register**, in text or Adobe Portable Document Format (PDF) on the Internet at the following site: *www.ed.gov/news/fedregister.*

To use PDF you must have Adobe Acrobat Reader, which is available free at this site. If you have questions about using PDF, call the U.S. Government Printing Office (GPO), toll free, at 1–888–293–6498; or in the Washington, DC, area at (202) 512–1530.

Note: The official version of this document is the document published in the **Federal Register.** Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available on GPO Access at: *www.gpoaccess.gov/nara/index.html.*

Dated: June 23, 2004.

Sally L. Stroup,

Assistant Secretary for Postsecondary Education.

[FR Doc. 04–14672 Filed 6–28–04; 8:45 am]

BILLING CODE 4000–01–P

ELECTION ASSISTANCE COMMISSION

Sunshine Act Notice

AGENCY: Election Assistance Commission.

* * * * * *

ACTION: Notice of public meeting.

DATE & TIME: Tuesday, July 13, 2004, at 1 p.m.

PLACE: U.S. Election Assistance Commission, 1225 New York Ave., NW., Suite 1100, Washington, DC 20005. (Metro stop: Metro Center).

STATUS: This meeting will be open to the public.

SUMMARY: The purpose of this meeting will be to receive general updates and reports on the following: EAC Administration, EAC Requirements

Payments to States, the EAC Standards Board and Board of Advisors, the EAC Technical Guidelines and Development Committee and the Commission's two public hearings conducted on May 5th and June 3rd. The Commission will also review recommendations on the following: Best Practices, a Grant to the National Student and Parent Mock Election, the National Voter Registration Form, a Public Hearing on Poll Worker Recruitment and Training, Electronic Voting Security Resolution and the November Election Research Project. The Commission will also receive the following presentations: U.S. Department of Justice Election Crimes Branch and the National Software Reference Library for the National Institute of Standards and Technology.

* * * * *

PERSON TO CONTACT FOR INFORMATION: Bryan Whitener, telephone: (202) 566–3100.

DeForest B. Soaries, Jr.,

Chairman, Election Assistance Commission.

[FR Doc. 04–14842 Filed 6–25–04; 1:05 pm]

BILLING CODE 6820–MP–M

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Paducah

AGENCY: Department of Energy (DOE).

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Paducah. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Thursday, July 15, 2004, 5:30 p.m.–9:30 p.m.

ADDRESSES: 111 Memorial Drive, Barkley Centre, Paducah, Kentucky 42001.

FOR FURTHER INFORMATION CONTACT: William E. Murphie, Deputy Designated Federal Officer, Department of Energy Portsmouth/Paducah Project Office, 1017 Majestic Drive, Suite 200, Lexington, Kentucky 40513, (859) 219–4001.

SUPPLEMENTARY INFORMATION: Purpose of the Board: The purpose of the Board is to make recommendations to DOE in the areas of environmental restoration, waste management and related activities.

Tentative Agenda

5:30 p.m.—Informal Discussion.

6 p.m.—Call to Order; Introductions; Review Agenda; Approval of June Minutes.

6:05 p.m.—DDFO's Comments.

6:25 p.m.—Ex-officio Comments.

6:35 p.m.—Federal Coordinator Comments.

6:45 p.m.—Public Comments and Questions.

6:55 p.m.—Break.

7:05 p.m.—Task Forces/Presentations.

- Waste Disposition.

—Burial Grounds Operable Unit.

- Water Quality.
- Long Range Strategy/Stewardship.

—Operating Procedures and Bylaws.

- Community Outreach.

8:05 p.m.—Public Comments and Questions.

8:15 p.m.—Administrative Issues.

- Review of Workplan.
- Review of Next Agenda.

8:35 p.m.—Review of Action Items.

8:50 p.m.—Subcommittee Reports.

- Executive Committee.

9:15 p.m.—Final Comments.

9:30 p.m.—Adjourn.

Copies of the final agenda will be available at the meeting.

Public Participation: The meeting is open to the public. Written statements may be filed with the Committee either before or after the meeting. Individuals who wish to make oral statements pertaining to agenda items should contact David Dollins at the address listed below or by telephone at (270) 441–6819. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Each individual wishing to make public comments will be provided a maximum of five minutes to present their comments as the first item of the meeting agenda.

Minutes: The minutes of this meeting will be available for public review and copying at the Freedom of Information Public Reading Room, 1E–190, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC 20585 between 9 a.m. and 4 p.m., Monday–Friday, except Federal holidays. Minutes will also be available at the Department of Energy's Environmental Information Center and Reading Room at 115 Memorial Drive, Barkley Centre, Paducah, Kentucky between 8 a.m. and 5 p.m. on Monday thru Friday or by writing to David Dollins, Department of Energy Paducah Site Office, Post Office Box 1410, MS–103, Paducah, Kentucky 42001 or by calling him at (270) 441–6819.

Issued in Washington, DC, on June 23, 2004.

Carol A. Matthews,

Acting, Deputy Advisory Committee Management Officer.

[FR Doc. 04–14685 Filed 6–28–04; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Environmental Management Site-Specific Advisory Board, Oak Ridge Reservation

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Environmental Management Site-Specific Advisory Board (EM SSAB), Oak Ridge. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of meetings be announced in the **Federal Register**.

DATES: Wednesday, July 14, 2004, 6 p.m.

ADDRESSES: DOE Information Center, 475 Oak Ridge Turnpike, Oak Ridge, TN.

FOR FURTHER INFORMATION CONTACT: Pat Halsey, Federal Coordinator, Department of Energy Oak Ridge Operations Office, P.O. Box 2001, EM–90, Oak Ridge, TN 37831. Phone (865) 576–4025; fax (865) 576–5333 or e-mail: *halseypj@oro.doe.gov* or check the Web site at *http://www.oakridge.doe.gov/em/ssab*.

SUPPLEMENTARY INFORMATION: Purpose of the Board: The purpose of the Board is to make recommendations to DOE in the areas of environmental restoration, waste management, and related activities.

Tentative Agenda: The meeting presentation will focus on the FY 2005 Oak Ridge Site-Specific Advisory Board work plan topics proposed by DOE, EPA, and the Tennessee Department of Environment and Conservation.

Public Participation: The meeting is open to the public. Written statements may be filed with the Committee either before or after the meeting. Individuals who wish to make oral statements pertaining to agenda items should contact Pat Halsey at the address or telephone number listed above. Requests must be received five days prior to the meeting and reasonable provision will be made to include the presentation in the agenda. The Deputy Designated Federal Officer is empowered to conduct the meeting in a fashion that will facilitate the orderly conduct of business. Each individual wishing to make public comment will be provided a maximum of five minutes to present their comments.

Minutes: Minutes of this meeting will be available for public review and copying at the Department of Energy's Information Center at 475 Oak Ridge Turnpike, Oak Ridge, TN between 8 a.m. and 5 p.m. Monday through Friday, or by writing to Pat Halsey, Department of Energy Oak Ridge Operations Office, P.O. Box 2001, EM–90, Oak Ridge, TN 37831, or by calling her at (865) 576–4025.

Issued in Washington, DC, on June 23, 2004.

Carol A. Matthews,

Acting Deputy Advisory Committee Management Officer.

[FR Doc. 04–14686 Filed 6–28–04; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Office of Science; Fusion Energy Sciences Advisory Committee

AGENCY: Department of Energy.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Fusion Energy Sciences Advisory Committee. The Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Monday, July 26, 2004, 9 a.m. to 6 p.m.; Tuesday, July 27, 2004, 9 a.m. to 12 noon.

ADDRESSES: The Marriott Gaithersburg Washingtonian Center, 9751 Washingtonian Boulevard, Gaithersburg, Maryland 20878, USA.

FOR FURTHER INFORMATION CONTACT: Albert L. Opdenaker, Office of Fusion Energy Sciences, U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585–1290; telephone: 301–903–4927.

SUPPLEMENTARY INFORMATION: *Purpose of the Meeting:* The purpose of this meeting is to hear from the FESAC the progress that it has made in fulfilling its charge to identify the major science and technology issues that need to be addressed, recommend how to organize campaigns to address those issues, and recommend the priority order in which the identified campaigns should be undertaken.

Tentative Agenda

Monday, July 26, 2004

- Office of Science Perspective.
- Office of Fusion Energy Sciences Perspective.
- Overview of the Priority Panel Efforts to Date.
- Presentations from the Six Working Groups.
- Public Comments.

Tuesday, July 27, 2004

- ITER Project Status.
- Further Discussions.
- Adjourn.

Public Participation: The meeting is open to the public. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of the items on the agenda, you should contact Albert L. Opdenaker at 301–903–8584 (fax) or *albert.opdenaker@science.doe.gov* (e-mail). You must make your request for an oral statement at least 5 business days before the meeting. Reasonable provision will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule.

Minutes: We will make the minutes of this meeting available for public review and copying within 30 days at the Freedom of Information Public Reading Room, IE–190, Forrestal Building, 1000 Independence Avenue, SW., Washington, DC, between 9 a.m. and 4 p.m., Monday through Friday, except Federal holidays.

Issued in Washington, DC, on June 23, 2004.

Carol A. Matthews,

Acting Deputy Advisory Committee Management Officer.

[FR Doc. 04–14687 Filed 6–28–04; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP04–358–000]

Algonquin Gas Transmission Company; Notice of Application

June 22, 2004.

Take notice that on June 14, 2004, Algonquin Gas Transmission Company (Algonquin) filed in Docket No. CP04–358–000 an application pursuant to section 7 of the Natural Gas Act (NGA) seeking a certificate of public convenience and necessity to construct, own, and operate 1.44 miles of 24-inch pipeline and appurtenant facilities in the City of Providence, Rhode Island, and also to establish initial rates for the facilities. The Algonquin facilities will provide a direct connection between the existing liquefied natural gas facility (LNG) of KeySpan LNG, L.P., with upgrades as described in Docket Nos. CP04–223–000 and CP04–293–000, and Algonquin's existing pipeline system. Algonquin states that the pipeline facilities are designed to provide firm transportation service for BG LNG Services, LLC of up to 500,000 Dth/day, as more fully described in its application.

Algonquin states that these applications are on file with the Commission and open to public inspection and 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" 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. Any initial questions regarding these applications should be directed to Steven E. Tillman, General Manager, Regulatory Affairs, Algonquin, Gas Transmission Company, P.O. Box 1642, Houston, Texas 77251–1642, phone: (713) 627–5113.

There are two ways to become involved in the Commission's review of this project. First, any person wishing to obtain legal status by becoming a party to the proceedings for this project should, on or before the below listed comment date, file with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, a motion to intervene in accordance with the requirements of the Commission's rules of practice and procedure (18 CFR 385.214 or 385.211) and the regulations under the NGA (18 CFR 157.10). A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies of all documents filed by the applicant and by all other parties. A party must submit 14 copies of filings made with the Commission and must mail a copy to the applicant and to every other party in the proceeding. Only parties to the proceeding can ask for court review of Commission orders in the proceeding.

However, a person does not have to intervene in order to have comments considered. The second way to participate is by filing with the Secretary of the Commission, as soon as possible, an original and two copies of comments in support of or in opposition to this project. The Commission will consider these comments in determining the appropriate action to be taken, but the filing of a comment alone will not serve to make the filer a party to the proceeding. The Commission's rules require that persons filing comments in opposition to the project provide copies of their protests only to the party or parties directly involved in the protest.

Persons who wish to comment only on the environmental review of this project should submit an original and two copies of their comments to the Secretary of the Commission. Those providing environmental comments will be placed on the Commission's environmental mailing list, will receive copies of the environmental documents, and will be notified of meetings associated with the Commission's environmental review process. The environmental commenters will not be required to serve copies of filed documents on all other parties. However, the non-party commenters will not receive copies of all documents filed by other parties or issued by the Commission (except for the mailing of environmental documents issued by the Commission) and will not have the right to seek court review of the Commission's final order.

Motions to intervene, protests and 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. The Commission strongly encourages electronic filings.

Comment Date: July 13, 2004.

Magalie R. Salas,

Secretary.

[FR Doc. E4–1432 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER04–734–000]

Barclays Bank PLC; Notice of Issuance of Order

June 21, 2004.

Barclays Bank PLC (Barclays Bank) filed an application for market-based rate authority, with an accompanying tariff. The proposed tariff provides for wholesale sales of capacity, energy, and ancillary services at market-based rates. Barclays Bank also requested waiver of various Commission regulations. In particular, Barclays Bank requested that the Commission grant blanket approval under 18 CFR part 34 of all future issuances of securities and assumptions of liability by Barclays Bank.

On June 2, as amended June 4, 2004, pursuant to delegated authority, the Director, Division of Tariffs and Market Development—South, granted the request for blanket approval under part 34, subject to the following:

Any person desiring to be heard or to protest the blanket approval of issuances of securities or assumptions of liability by Barclays Bank should file a motion to intervene or protest 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).

Notice is hereby given that the deadline for filing motions to intervene or protests, is July 2, 2004.

Absent a request to be heard in opposition by the deadline above, Barclays Bank is authorized to issue securities and assume obligations or liabilities as a guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issuance or assumption is for some lawful object within the corporate purposes of Barclays Bank, compatible with the public interest, and is reasonably necessary or appropriate for such purposes.

The Commission reserves the right to require a further showing that neither public nor private interests will be adversely affected by continued approval of Barclays Bank's issuances of securities or assumptions of liability.

Copies of the full text of the Order are available from the Commission's Public Reference Branch, 888 First Street, NE., Washington, DC 20426. The Order may also be viewed on the Commission's Web site at *http://www.ferc.gov*, using the e library (FERRIS) link. Enter the docket number excluding the last three digits in the docket number filed to access the document. 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 electronic filings.

Magalie R. Salas,

Secretary.

[FR Doc. E4–1440 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL04–108–000]

Public Utilities Providing Service in California Under Sellers' Choice Contracts; Notice of Initiation of Proceeding and Refund Effective Date

June 22, 2004.

On June 17, 2004, the Commission issued an order in the above-referenced dockets initiating a proceeding in Docket No. EL04–108–000 under section 206 of the Federal Power Act concerning issues related to sellers' choice contracts.

The refund effective date in Docket No. EL04–108–000, established pursuant to section 206(b) of the Federal Power Act will be 60 days following publication of this notice in the **Federal Register**.

Magalie R. Salas,

Secretary.

[FR Doc. E4–1434 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. ER04–699–000, ER03–1272–002, ER98–4410–000, ER98–4410–001, ER98–4410–002, EL02–101–000, EL02–101–001, and EL02–101–002]

Entergy Services, Inc., CLECO Power, LLC, Dalton Utilities, Entergy Services, Inc., Georgia Transmission Corporation, JEA, MEAG Power, Sam Rayburn G&T Electric Cooperative, Inc., Southern Company Services, Inc., City of Tallahassee, Florida; Supplemental Notice of Technical Conference

June 21, 2004.

As announced in the Notice of Technical Conference issued on May 12, 2004, a technical conference will be held on July 29–30, 2004, in New Orleans, Louisiana, to discuss with States and market participants issues related to Entergy Services, Inc.'s filing to establish independent oversight over certain transmission system activities. The conference will be held from 1 p.m. to 5 p.m. (central time) on July 29th and from 9 a.m. to approximately 3 p.m. (central time) on July 30th. The conference will be held at the City of New Orleans' City Council Chambers, located on the First Floor of 1300 Perdido Street, New Orleans, Louisiana

70112. Members of the Federal Energy Regulatory Commission are expected to participate, along with Entergy's State and local utility regulators.

The conference is open for the public to attend, and registration is not required; however, in-person attendees are asked to register for the conference on-line by close of business on Monday, July 26, 2004 at *http://www.ferc.gov/whats-new/registration/entergy-0729-form.asp*.

The Commission believes that there may be issues that overlap in these proceedings which may affect the overall provision of transmission service on the Entergy System. The Commission intends that the technical conference it ordered in these dockets will enable regulators and interested parties to discuss issues raised by Entergy's various proposals in the above dockets.

The Commission asks that the participants in the technical conference address the reasonableness of Entergy's proposal in Docket No. ER04–699–000 to establish an Independent Coordinator of Transmission (ICT) to provide oversight over Entergy's transmission system as opposed to the reasonableness and feasibility of alternative arrangements to provide oversight or control over Entergy's transmission system. The Commission would like Entergy and parties to the various referenced proceedings to address the issues raised in those proceedings as they relate to the broader issue of transmission service on the Entergy System. As such, the Commission expects to discuss how the following Entergy cases pending at the Commission in relation to Entergy's ICT proposal: The Available Flowgate Capability proceeding in Docket Nos. ER03–1272–000, *et al.*; the Capacity Benefit Margin proceeding in Docket Nos. ER01–4410–000, *et al.*; and the transmission expansion pricing and Weekly Procurement Process (WPP) contained in Docket No. ER04–699–000.

The Commission would also like to consider the issues raised by Indicated Stakeholders [1] in Docket Nos. EL02–101–000, *et al.* in its filed response to the announcement of the SeTrans Sponsors that efforts to establish a Regional Transmission Organization in the Southeastern United States, including Entergy's transmission facilities, were suspended.

The Commission expects that other issues may be added after the Commission receives comments in Docket No. ER04–699–000 and will publish an additional supplemental notice with a detailed agenda. As a preliminary matter, the general issues to be addressed at each session of the conference are discussed below.

Day One of the conference will focus on issues regarding Entergy's oversight proposal, including whether the ICT's duties and responsibilities are adequate to ensure non-discriminatory access on the Entergy Transmission System; actual independence of the ICT; independent third party administration of Entergy's OASIS; and broad Entergy System Agreement issues. Additional issues may include feasibility of SPP serving as the ICT and the possibility of Entergy joining the SPP RTO.

Day Two of the conference will focus on transmission access issues arising from Entergy's proposed WPP, participation in the WPP, the roles of the EMO, Entergy Transmission Function—Weekly Operations, re-dispatch costs and impacts on AFC. Entergy's proposed transmission pricing and expansion pricing proposal will also be discussed.

Transcripts of the conference will be immediately available from Ace Reporting Company ((202) 347–3700 or 1–800–336–6646) for a fee. They will be available for the public on the Commission's eLibrary (FERRIS) seven calendar days after FERC receives the transcript. Additionally, Capitol Connection offers the opportunity for remote listening of the conference via the Internet or a Phone Bridge Connection for a fee. Interested persons should make arrangements as soon as possible by visiting the Capitol Connection Web site at *http://www.capitolconnection.gmu.edu* and clicking on "FERC." If you have any questions contact David Reininger or Julia Morelli at the Capitol Connection ((703) 993–3100).

For more information about the conference, please contact Anna Cochrane at (202) 502–6357 or at *anna.cochrane@ferc.gov*.

Linda Mitry,

Acting Secretary.

[FR Doc. E4–1441 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

[1] The Indicated Stakeholders are: Alabama Municipal Electric Authority; Arkansas Electric Cooperative Corporation; ChevronTexaco; Electricities of North Carolina, Inc.; Lafayette Utilities System; Louisiana Energy and Power Authority; NRG Energy; Shell Trading Gas and Power Company; Tractebel Energy Marketing, Inc.; and Williams Power Company, Inc.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. CP04–36–000 and CP04–41–000]

Weaver's Cove Energy L.L.C. and Mill River Pipeline L.L.C.; Notice of Public Meeting Attendance

June 22, 2004.

On Wednesday, June 30, 2004, staff of the Office of Energy Projects (OEP) will participate in a public meeting held by State Representative Joseph N. Amaral in Tiverton, Rhode Island regarding Weaver's Cove Energy, L.L.C.'s proposed liquefied natural gas (LNG) import terminal and storage facility in Fall River, Massachusetts. The public meeting will start at 7 p.m. (e.s.t.) at the Patriot's Club (formerly the Ponta Delgada Club) on 70 Shove Street in Tiverton, Rhode Island.

Magalie R. Salas,

Secretary.

[FR Doc. E4–1433 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket Nos. RP03–398–000, and RP04–155–000 (Consolidated)]

Northern Natural Gas Company; Notice of Informal Settlement Conference

June 21, 2004.

Take notice that an informal settlement conference will be convened in this proceeding at the offices of the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 commencing at 1 p.m. on Monday, June 28, 2004, and continuing, if necessary, at 9:30 a.m. on Tuesday, June 29, 2004 (e.s.t.), in a room to be announced later, for the purpose of exploring the possible settlement of the above-referenced dockets.

Any party, as defined by 18 CFR 385.102(c), or any participant as defined by 18 CFR 385.102(b), is invited to attend. Persons wishing to become a party must move to intervene and receive intervenor status pursuant to the Commission's regulations (18 CFR 385.214).

For additional information, please contact Kevin Frank (202) 502–8065 *kevin.frank@ferc.gov*, Gopal Swaminathan (202) 502–6132, *gopal.swaminathan@ferc.gov*, or

William Collins (202) 502–8248
william.collins@ferc.gov.

Magalie R. Salas,
Secretary.

[FR Doc. E4–1438 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PL04–11–000, PA04–14–000, EL04–52–000, ER03–262–009 et al., ER04–691–000 and EL04–104–000, ER04–367–000 et al., ER04–521–001 et al., ER04–375–000 et al., ER04–364–000, PL04–5–000]

Summer 2004 Reliability Workshop, Ohio Edison Company, Toledo Edison Company, Cleveland Electric Illuminating Company, and Pennsylvania Power Company, Reporting by Transmission Providers on Vegetation Management Practices Related to Designated Transmission Facilities, New PJM Companies, et al., Midwest Independent Transmission, System Operator, Inc. et al., PJM Interconnection, LLC et al., PJM Interconnection, LLC, Midwest Independent Transmission System Operator, Inc. et al., Commonwealth Edison Company et al., Policy Statement on Matters Related to Bulk Power System Reliability; Notice of Technical Conference

June 21, 2004.

Take notice that a technical conference will be held to address what steps have been taken to prevent a blackout reoccurrence and discuss related reliability issues in the Midwest for the Summer 2004, on Thursday, July 15, from approximately 9 a.m. to 4:30 p.m. (eastern daylight time) at the Renaissance Cleveland Hotel, 24 Public Square, Cleveland, Ohio. Members of the Commission will attend and participate in the discussions.

The Renaissance Cleveland Hotel is holding a block of rooms for attendees at the rate of $139 for the evening of July 14. For reservations call 1–800–HOTELS–1 or (216) 696–5600.

The conference is open for the public to attend, and registration is not required; however, in-person attendees are asked to register for the conference on-line by close of business on Thursday, July 8, at *http://www.ferc.gov/whats-new/registration/reliability-workshop-0715-form.asp.*

A tentative agenda for this meeting is included with this notice as Attachment A. The discussion covers responses to the 2003 blackout, preparations for Summer 2004, electricity infrastructure issues, and longer-term reliability issues. A more detailed agenda, with a list of speakers, will be published at a later time.

The meeting was established in response to an invitation by Governor Bob Taft of Ohio to convene a public forum and technical conference to address these issues. The conference will also enjoy the participation of members of the Public Utilities Commission of Ohio.

Transcripts of the conference will be immediately available from Ace Reporting Company ((202) 347–3700 or 1–800–336–6646) for a fee. They will be available for the public on the Commission's eLibrary system seven calendar days after FERC receives the transcript. Additionally, Capitol Connection offers the opportunity for remote listening of the conference via Real Audio or a Phone Bridge Connection for a fee. Persons interested in making arrangements should contact David Reininger or Julia Morelli at the Capitol Connection ((703) 993–3100) as soon as possible or visit the Capitol Connection Web site at *http://www.capitolconnection.org* and click on "FERC."

For more information about the conference, please contact Sarah McKinley at (202) 502–8004 or *sarah.mckinley@ferc.gov.*

Magalie R. Salas,
Secretary.

Attachment A

Agenda

9 a.m.—Opening comments: Chairman Pat Wood, Federal Energy Regulatory Commission; Governor Bob Taft of Ohio; Chairman Alan R. Schriber, Public Utilities Commission of Ohio.

9:20 a.m.—Preparations for summer 2004: First Energy, improvements to grid operations and practices, implementation of NERC recommendations; AEP, operations and summer preparation; Midwest ISO, software, operations, communications; PJM, discussion of Commonwealth Edison and AEP integration, the common market, operations and communications; TVA, operations and preparations; NERC, blackout mitigation recommendations and implementation; Vegetation Management status, speaker from NARUC or FERC; Audience Participation.

11:20 a.m.—Break.

11:40 a.m.—Midwest Infrastructure Issues (OH, MI, WI, IL, IN, KY, TN, WV). Jeff Wright, FERC—Update on Midwest electric and gas infrastructure. MISO—Midwest transmission planning, issues and prospects. Audience Participation.

12:40 p.m.—Lunch Break.

2 p.m.—Longer-Term Reliability Issues: DOE, Implementation of blackout recommendations; NERC, Reliability readiness audits; NERC reliability standards; State-level actions—Regulators representing NARUC, Ohio, Michigan, New York, Indiana; Audience participation.

4 p.m.—Next Steps: Commitments and Recommendations: Discussion with FERC and State Regulators, DOE, and audience.

4:30 p.m.—Adjourn.

[FR Doc. E4–1439 Filed 6–28–04; 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

June 22, 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 merits 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.

Prohibited

Docket number	Date filed	Presenter or requester
1. CP01–49–000	6–17–04	Edmee Van Haeften.
2. CP04–58–000	6–14–04	Khalid Ibrahim, *et al.* [1]
3. EL03–235–000	6–14–05	Robert Wilmouth.
4. Project No. 516–388	6–16–04	Kenneth and Sandy Fox.

[1] This communication is one among numerous form letters sent to the Commission by the Greenpeace, USA organization. Only representative samples of these prohibited non-decisional documents are posted in this docket on the Commission's eLibrary system (*http://www.ferc.gov*).

Exempt

Docket number	Date filed	Presenter or requester
1. CP04–37–000, CP04–44–000, CP04–45–000, CP04–46–000	5–20–04	Hon. Ken Armbrister.
2. CP04–37–000, CP04–44–000, CP04–45–000, CP04–46–000	5–25–04	Hon. Dennis Bonnen.
3. CP04–37–000,	6–7–04	Sydne Marshall *et al.*
4. CP04–37–000, CP04–44–000, CP04–45–000, CP04–46–000	6–10–04	Hon. Jerry Patterson.
5. CP04–47–000, CP04–38–000	6–1–04	Hon. Kathleen Babnieaux Blanco.
6. CP04–58–000	6–1–04	Hon. Betty Karnette.
7. ER04–23–001	5–25–04	Hon. Joseph Lieberman, Hon. Rosa L. DeLauro, Hon. Christopher Shays, Hon. Christopher Dodd, Hon. John Larson.
8. Project No. 1413–000	6–17–04	Nicholas Jayjack.
9. Project No. 2042–013	6–3–04	Hon. George R. Nethercutt, Jr.
10. Project No. 2082–027	6–8–04	Ronnie Pellegrini.
11. Project No. 2082–000	6–17–01	Stephen D. Mikesell.

Magalie R. Salas,

Secretary.

[FR Doc. E4–1431 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PL04–10–000]

Federal Power Act; Section 305(b) Obligations; Order Advising Public Utilities and Their Officers and Directors of Federal Power Act Section 305(b) Obligations

June 22, 2004.

Before Commissioners: Pat Wood, III, Chairman; Nora Mead Brownell, Joseph T. Kelliher, and Suedeen G. Kelly.

1. Under section 305(b) of the Federal Power Act (FPA),[1] any person seeking to hold the positions of officer or director of a public utility and officer or director of another public utility, or an electrical equipment supplier, or securities underwriter (with certain statutorily-defined exceptions) must seek prior Commission approval to hold any such positions.

2. The Commission's regulations [2] require that an application for approval be filed with the Commission within thirty (30) days of election or appointment to a qualifying position.[3] If an application is filed after the 30-day period, it is considered late. The Commission is concerned about the timeliness of applications. The Commission has previously stated that it "does not look favorably on untimely applications to hold interlocking positions." [4] Furthermore, if individuals or public utilities are confused or unclear about whether positions mandate prior Commission approval under section 305(b), they are strongly encouraged to "[seek] Commission clarification promptly." [5]

3. While the statute applies to the individual officer or director, the Commission urges public utilities to exercise due diligence when selecting individuals to serve as officers or directors and to ensure that current officers or directors are in compliance with the requirements of section 305(b). Furthermore, the Commission expects that all individuals who seek to serve or are serving as an officer or director of a public utility will be aware of their responsibilities under section 305(b) of the FPA and will comply with all requirements.

4. This order is intended to reiterate these obligations and emphasize the importance the Commission places on compliance with the statute. The Commission will exercise remedial authority, as appropriate, to persons that fail to obtain the prior approval required by FPA section 305(b).

5. The Secretary is directed to publish this order in the **Federal Register**.

By the Commission.

Linda Mitry,

Acting Secretary.

[FR Doc. 04–14655 Filed 6–28–04; 8:45 am]

BILLING CODE 6717–01–P

[1] 16 U.S.C. 825d (2000).

[2] 18 CFR part 45 (2003).

[3] Certain interlocking positions require only a more limited filing under our regulations. *See* 18 CFR 45.9 (2003). Likewise, individuals holding other interlocking positions are permitted to make a more limited filing under our precedent. *See, e.g.,* San Manuel Power Company LLC, 96 FERC ¶ 61,089 at 61,371 and Ordering Paragraph (E) (2001); Bridgeport Energy LLC, 83 FERC ¶ 61,307 at 62,262 and Ordering Paragraph (E) (1998).

[4] Thomas Madison McDaniel, Jr., 24 FERC ¶ 61,026 at 61,107 (1983).

[5] Walter F. Torrance, Jr., 29 FERC ¶ 61,288 at 61,588 (1984).

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7779–7]

Agency Information Collection Activities OMB Responses

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This document announces the Office of Management and Budget's (OMB) responses to Agency clearance requests, in compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et. seq.*). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information 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.

FOR FURTHER INFORMATION CONTACT: Susan Auby (202) 566–1672, or e-mail at *auby.susan@epa.gov* and please refer to the appropriate EPA Information Collection Request (ICR) Number.

SUPPLEMENTARY INFORMATION:

OMB Responses to Agency Clearance Requests

OMB Approvals

EPA ICR No. 1249.07; Recordkeeping Requirements for Certified Applications Using 1080 Collars for Livestock Protection; was approved 05/14/2004; OMB Number 2070–0074; expires 05/31/2007.

EPA ICR No. 1204.09; Submission of Unreasonable Adverse Effects Information Under FIFRA Section 6 (a) (2); was approved 05/14/2004; OMB Number 2070–0039; expires 05/31/2007.

EPA ICR No. 0276.12; Application for Experimental Use Permit (EUP) to Ship and Use a Pesticide for Experimental Purposes; in 40 CFR part 172; was approved 05/13/2004; OMB Number 2070–0040; expires 05/31/2007.

EPA ICR No. 0116.07; Emission Control System Performance Warranty Regulations and Voluntary Aftermarket Part Certification Program; in 40 CFR part 85, subpart V; was approved 05/07/2004; OMB Number 2060–0060; expires 05/31/2007.

EPA ICR No. 1857.03; Emission Reporting Requirements for Ozone SIP Revisions Relating to Statewide Budget for NO_X Emissions to Reduce the Regional Transport of Ozone; in 40 CFR 51.121 and 40 CFR 51.122; was approved 05/10/2004; OMB Number 2060–0445; expires 05/31/2007.

EPA ICR No. 1869.03; NESHAP for the Manufacture of Amino/Phenolic Resins; in 40 CFR part 63, subpart OOO; was approved 05/17/2004; OMB Number 2060–0434; expires 05/31/2007.

EPA ICR No. 1790.03; NESHAP for Phosphoric Acid Manufacturing and Phosphate Fertilizer Production Plants; in 40 CFR part 63, subparts AA and BB); was approved 5/18/2004; OMB Number 2060–0361; expires 05/31/2007.

EPA ICR No. 1678.05; NESAP for Magnetic Tape Manufacturing Operations; in 40 CFR part 63, subpart EE); was approved 05/17/2004; OMB Number 2060–0326; expires 05/31/2007.

EPA ICR No. 2149.01; Detroit Exposure and Aerosol Research Study (DEARS); was approved 06/01/2004; OMB Number 2080–00071; expires 06/20/2007.

EPA ICR No. 1717.04; NESHAP for Off-Site Waste and Recovery Operations; in 40 CFR part 63, subpart DD; was approved 05/21/2004; OMB Number 2060–0313; expires 05/31/2007.

EPA ICR No. 1783.03; NESHAP for Flexible Polyurethane Foam Production; in 40 CFR part 63, subpart III; was approved 05/21/2004; OMB Number 2060–0357; expires 05/13/2007.

EPA ICR No. 1214.06; Pesticide Product Registration Maintenance Fee; was approved 05/19/2004; OMB Number 2070–0100; expires 05/31/2007.

EPA ICR No. 1135.08; NSPS for Magnetic Tape Coating Facilities; in 40 CFR part 60, subpart SSS; was approved 06/25/2004; OMB Number 2060–0171; expires 06/20/2007.

Short Term Extensions

EPA ICR No. 1953.02; Information Collection Request for Best Management Practices Alternatives, Effluent Limitations Guidelines and Standards, Oil and Gas Extraction Point Source Category; in 40 CFR part 435; OMB Number 2040–0230; in 04/26/2004; OMB extended the expiration to 07/13/204.

Withdrawn

EPA ICR No. 2126.01; Longitudinal Study of Your Children's Exposures in their Homes to Selected Pesticides, Phthalates, Brominated Flame Retardants, and Perfluorinated Chemicals (CHEERS); was withdrawn by OMB 06/0/2004.

Comment Filed

EPA ICR No. 1189.13; Identification Listing and Rulemaking Petitions (Proposed Rule for Organic Dyes and/or Pigments Production Wastes); OMB Number 2050–0053; OMB filed comment on 06/25/2004.

Dated: June 21, 2004.

Oscar Morales,

Director, Collection Strategies Division.

[FR Doc. 04–14703 Filed 6–28–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[OAR–2004–0082, FRL–7779–6]

Agency Information Collection Activities: Proposed Collection; Comment Request; Reporting and Recordkeeping Requirements Under EPA's Natural Gas STAR Program, EPA ICR Number 1736.04, OMB Control Number 2060–0328

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 EPA is planning to submit the following continuing Information Collection Request (ICR) to the Office of Management and Budget (OMB). This is a request to renew an existing approved collection. This ICR is scheduled to expire on 11/30/04. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before August 30, 2004.

ADDRESSES: Submit your comments, referencing docket ID number OAR–2004–0082, to EPA online using EDOCKET (our preferred method), by e-mail to *a-and-r-Docket@epa.gov*, or by mail to: EPA Docket Center, Environmental Protection Agency, Air and Radiation Docket and Information Center, MC 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460.

FOR FURTHER INFORMATION CONTACT: Kevin Tingley at EPA's Natural Gas STAR Program by phone at (202) 343–9086, by e-mail at *tingley.kevin@epa.gov* or by fax at (202) 343–2208.

SUPPLEMENTARY INFORMATION: EPA has established a public docket for this ICR under Docket ID number OAR–2004–0082, which is available for public viewing at the Air and Radiation 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 Air and Radiation Docket and Information Center is (202) 566–1742. An electronic version of the public docket is available through EPA Dockets (EDOCKET) at *http://www.epa.gov/edocket.* Use EDOCKET to obtain a copy of the draft collection of information, 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. Once 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 within 60 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, 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 *www.epa.gov./edocket.*

Affected entities: Entities potentially affected by this action are those which produce, process, transport, and distribute natural gas.

Title: "Reporting and Recordkeeping Requirements Under EPA's Natural Gas STAR Program", EPA ICR Number 1736.04, OMB Control Number 2060–0328, expiring on 11/30/2004.

Abstract: Natural Gas STAR is an EPA-sponsored, voluntary program that encourages natural gas companies to adopt cost effective methods for reducing methane emissions. Natural Gas STAR Partners agree to implement cost-effective Best Management Practices, which will save participants money and improve environmental quality. EPA needs to collect information to establish program participation and to obtain general information on new Natural Gas STAR Partners. EPA also uses the information collection to evaluate a Partner's progress and performance, assess overall program results, and develop technical guidance documents for the benefit of the industry. Information collection is accomplished through the use of an annual reporting process that allows companies to report their accomplishments in either a traditional hard-copy format or electronically. Participation in Natural Gas STAR is voluntary. Natural Gas STAR Partners may designate information submitted under this ICR as confidential business information. EPA will treat all such information as confidential business information and will not make the company or agency-specific information collected under this ICR available to the general public. 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.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(ii) evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) enhance the quality, utility, and clarity of the information to be collected; and

(iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 47 hours per facility. 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: 111.

Estimated Number of Respondents: 111.

Frequency of Response: varies.

Estimated Total Annual Hour Burden: 5,217 hours.

Estimated Total Annualized Cost Burden: $382,335.

Dated: June 16, 2004.

Kathleen Hogan,

Director, Climate Protection Partnership Division.

[FR Doc. 04–14705 Filed 6–28–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–7779–5]

Access to Confidential Business Information by Enrollees Under the Senior Environmental Employment Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has authorized grantee organizations under the Senior Environmental Employment (SEE) Program, and their enrollees; access to information which has been submitted to EPA under the environmental statutes administered by the Agency. Some of this information may be claimed or determined to be confidential business information (CBI).

DATES: Comments concerning CBI access will be accepted until July 6, 2004.

ADDRESSES: Comments should be submitted to: Susan Street, National Program Director, Senior Environmental Employment Program (MC 3650A), U.S. Environmental Protection Agency; Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460. (Telephone (202) 564—0410).

SUPPLEMENTARY INFORMATION: The Senior Environmental Employment (SEE) program is authorized by the Environmental Programs Assistance Act of 1984 (Pub. L. 98–313), which provides that the Administrator may "make grants or enter into cooperative agreements" for the purpose of "providing technical assistance to: Federal, State, and local environmental agencies for projects of pollution prevention, abatement, and control." Cooperative agreements under the SEE program provide support for many functions in the Agency, including clerical support, staffing hot lines, providing support to Agency enforcement activities, providing library services, compiling data, and support in scientific, engineering, financial, and other areas.

In performing these tasks, grantees and cooperators under the SEE program and their enrollees may have access to potentially all documents submitted under the Resource Conservation and Recovery Act (RCRA), Clean Air Act (CAA), Clean Water Act (CWA), Safe Drinking Water Act (SDWA), Federal Insecticide, Fungicide and Rodenticide Act (FIFRA), Emergency Planning And Community Rights to Know Act (EPCRA) and Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), to the extent that these statutes allow disclosure of confidential information to authorized representatives of the United States (or to "contractors" under the Federal Insecticide, Fungicide, and Rodenticide Act). Some of these documents may contain information claimed as confidential.

EPA provides confidential information to enrollees working under the following cooperative agreements:

Cooperative agreement number	Organization
	National Association for Hispanic Elderly
CQ–830339	NAHE
CQ–831334	NAHE
	National Asian Pacific Center on Aging
CQ–831497	NAPCA
CQ–831498	NAPCA
CQ–831499	NAPCA
CQ–831500	NAPCA
CQ–831501	NAPCA
CQ–831534	NAPCA
	National Caucus and Center on Black Aged, Inc.
CQ–830980	NCBA
CQ–831569	NCBA
CQ–829751	NCBA
	National Council On the Aging, Inc.
CQ–831427	NCOA
CQ–831496	NCOA
CQ–831653	NCOA
	National Older Worker Career Center
CQ–830918	NOWCC
CQ–830969	NOWCC
CQ–831021	NOWCC
CQ–831022	NOWCC
CQ–831023	NOWCC
	Senior Service America, Inc.
CQ–831289	SSAI
CQ–831621	SSAI

Among the procedures established by EPA confidentiality regulations for granting access is notification to the submitters of confidential data that SEE grantee organizations and their enrollees will have access. 40 CFR 2.201(h)(2)(iii). This document is intended to fulfill that requirement.

The grantee organizations are required by the cooperative agreements to protect confidential information. SEE enrollees are require to sign confidentiality agreements and to adhere to the same security procedures as Federal employees.

Dated: June 9, 2004.

Linda Wallace,

Director, Customer Services Support Center (3650A).

[FR Doc. 04–14704 Filed 6–28–04; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[OPP–2004–0147; FRL–7363–8]

Zinc Pyrithione (Formerly Known as Omadine Salts) Preliminary Risk Assessment; Notice of Availability

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces the availability of EPA's preliminary risk assessment, and related documents for the antimicrobial pesticide zinc pyrithione (also referred to as zinc omadine), and opens a public comment period on these documents. The Agency has changed the reregistration case name for this chemical from "omadine salts" to "zinc pyrithione" to accurately reflect the sole active ingredient in this case. Previously, the omadine salts case contained two active ingredients (zinc omadine and tert-butylamine 2-pyridinethiol-1-oxide). The rationale for changing the case name is that: Omadine is a registered trade name and the Agency prefers not to use trade names as titles of documents; the plural "salts" in the case name indicates multiple actives but there is only one chemical being considered (i.e., zinc pyrithione); harmonize the case name with the sole active ingredient; and the second chemical previously listed in this case (i.e., tert-butylamine 2-pyridinethiol-1-oxide; PC code 088005) has no active registered products and is no longer a registered active ingredient. The public also is encouraged to suggest risk management ideas or proposals to address the risks identified. EPA is developing a Reregistration Eligibility Decision (RED) for zinc pyrithione using a modified, four-phase public participation process. EPA uses this process to involve the public in developing pesticide reregistration and tolerance reassessment decisions. Through these programs, EPA is ensuring that all pesticides meet current health and safety standards.

DATES: Comments, identified by docket ID number OPP–2004–0147, must be received on or before August 30, 2004.

ADDRESSES: Comments may be submitted electronically, by mail, or through hand delivery/courier. Follow the detailed instructions as provided in Unit I.C. of the **SUPPLEMENTARY INFORMATION.**

FOR FURTHER INFORMATION CONTACT: Tony Kish, Antimicrobials Division (7510C), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001; telephone number: 703–308–9443; fax number: 703–308–8481; e-mail address: *kish.tony@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does This Action Apply to Me?

This action is directed to the public in general, and may be of interest to a wide range of stakeholders including environmental, human health, and agricultural advocates; the chemical industry; pesticide users; and members of the public interested in the use of pesticides. Since others also may be interested, the Agency has not attempted to describe all the specific entities that may be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed under **FOR FURTHER INFORMATION CONTACT.**

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

1. *Docket.* EPA has established an official public docket for this action under docket identification (ID) number OPP–2004–0147. 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 Public Information and Records Integrity Branch (PIRIB), Rm. 119, Crystal Mall #2, 1921 Jefferson Davis Hwy., Arlington, VA. This docket facility is open from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The docket telephone number is (703) 305–5805.

2. *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 ID 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. 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 in Unit I.B. 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.

C. 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 ID 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. If you wish to submit CBI or information that is otherwise protected by statute, please follow the instructions in Unit I.D. Do not use EPA Dockets or e-mail to submit CBI or information protected by statute.

1. *Electronically.* If you submit an electronic comment as prescribed in this unit, 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.

i. *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. Once in the system, select "search," and then key in docket ID number OPP–2004–0147. 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.

ii. *E-mail.* Comments may be sent by e-mail to *opp-docket@epa.gov*, Attention: Docket ID Number OPP–2004–0147. 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.

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

2. *By mail.* Send your comments to: Public Information and Records Integrity Branch (PIRIB) (7502C), Office of Pesticide Programs (OPP), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460–0001, Attention: Docket ID Number OPP–2004–0147.

3. *By hand delivery or courier.* Deliver your comments to: Public Information and Records Integrity Branch (PIRIB), Office of Pesticide Programs (OPP), Environmental Protection Agency, Rm. 119, Crystal Mall #2, 1921 Jefferson Davis Hwy., Arlington, VA, Attention: Docket ID Number OPP–2004–0147. Such deliveries are only accepted during the docket's normal hours of operation as identified in Unit I.B.1.

D. 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. 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 listed under **FOR FURTHER INFORMATION CONTACT**.

E. 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 ID 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.

II. What Action Is the Agency Taking?

EPA is releasing for public comment its human health and environmental fate and effects risk assessment(s), and related documents for zinc pyrithione, an antimicrobial pesticide and encouraging the public to suggest risk management ideas or proposals. Zinc pyrithione is used as a materials preservative, as an antifoulant for boat paints, and as an industrial laundry additive. EPA developed the risk assessment(s) for zinc pyrithione through a modified version of its public process for making pesticide reregistration eligibility and tolerance reassessment decisions. Through these programs, EPA is ensuring that pesticides meet current standards under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) and the Federal Food, Drug, and Cosmetic Act (FFDCA), as amended by the Food Quality Protection Act of 1996 (FQPA) and the Pesticide Registration Improvement Act of 2003 (PRIA).

EPA is providing an opportunity, through this notice, for interested parties to provide written comments and input on the Agency's risk assessment(s) for zinc pyrithione. Such comments and input could address, for example, the availability of additional data to further refine the risk assessments, or could address the Agency's risk assessment methodologies and assumptions as applied to this specific pesticide.

EPA seeks to achieve environmental justice, the fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, in the development, implementation, and enforcement of environmental laws, regulations, and policies. To help address potential environmental justice issues, the Agency seeks information on any groups or segments of the population who, as a result of their location, cultural practices, or other factors, may have atypical, unusually high exposure to zinc pyrithione, compared to the general population.

All comments should be submitted using the methods in Unit I.C., and must be received by EPA on or before the closing date. Comments will become part of the Agency record for zinc pyrithione.

EPA is applying the principles of public participation to all pesticides undergoing reregistration and tolerance reassessment. In conducting these programs, the Agency is tailoring its public participation process to be commensurate with the level of risk, extent of use, complexity of the issues, and degree of public concern associated with each pesticide. For zinc pyrithione, a modified, four-phase process with one comment period and ample opportunity for public consultation seems appropriate in view of its refined risk assessment. However, if as a result of comments received during this comment period EPA finds that additional issues warranting further discussion are raised, the Agency may lengthen the process and include a second comment period, as needed. EPA plans to issue the zinc pyrithione RED as a final document for public comment.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: June 17, 2004.

Frank Sanders,

Director, Antimicrobials Division, Office of Pesticide Programs.

[FR Doc. 04–14706 Filed 6–28–04 8:45 am]

BILLING CODE 6560–50–S

GENERAL SERVICES ADMINISTRATION

Office of Governmentwide Policy; Cancellation of an Optional Form

AGENCY: General Services Administration.

ACTION: Notice.

SUMMARY: Because of low usage, the following Optional Form is cancelled: OF 16, Sales Slip.

FOR FURTHER INFORMATION CONTACT: Ms. Barbara Williams, (202) 501–0581.

DATES: Effective June 29, 2004.

Dated: June 21, 2004.

Barbara M. Williams,

Deputy Standard and Optional Forms Management Officer.

[FR Doc. 04–14683 Filed 6–28–04; 8:45 am]

BILLING CODE 6820–34–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[60Day–04–68]

Proposed Data Collections Submitted for Public Comment and Recommendations

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 for opportunity for public comment on proposed data collection projects, the Centers for Disease Control and Prevention (CDC) will publish periodic summaries of proposed projects. To request more information on the proposed projects or to obtain a copy of the data collection plans and instruments, call the CDC Reports Clearance Officer on (404) 498–1210.

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. Send comments to Sandra Gambescia, CDC Assistant Reports Clearance Officer, 1600 Clifton Road, MS–E11, Atlanta, GA 30333 or send an e-mail to *omb@cdc.gov*. Written comments should be received within 60 days of this notice.

Proposed Project

National Blood Lead Surveillance System (OMB No. 0920–0337) — Extension — National Center for Environmental Health, Centers for Disease Control and Prevention. CDC, National Center for Environmental Health began the National Childhood Lead Surveillance Program in 1992. The goals of the childhood lead surveillance program are to: (1) Establish childhood lead surveillance systems at the state and national levels; (2) use surveillance data to estimate the extent of elevated blood-lead levels (BLLs) among children; (3) assess the follow-up of children with elevated blood-lead levels; (4) examine potential sources of lead exposure; and (5) help allocate resources for lead poison prevention activities. State surveillance systems are based on reports of blood-lead tests from laboratories. Ideally, laboratories report results of all lead tests (not just elevated values) to the state health department; however, each state determines the reporting level for blood-lead tests. In addition to blood-lead test results, state child-specific surveillance databases contain follow-up data on children with elevated blood-lead levels including data on medical treatment, environmental investigations, and potential sources of lead exposure. Surveillance data for the national database are extracted from the state child tracking databases and transferred to CDC.

Since 1987, CDC has sponsored the state-based Adult Blood Lead Epidemiology and Surveillance (ABLES) program to track cases of elevated BLLs among persons ages 16 years and older, and provide intervention consultation and other assistance. The public health objective of the ABLES program, as stated in Healthy People 2010, is to reduce the number of persons with BLLs ≥25 μ/dL from work exposures to zero by 2010. The ABLES program seeks to accomplish its objective by continuing to improve its surveillance programs and helping state health and other agencies to effectively intervene to prevent further lead exposures. Intervention strategies implemented by state ABLES-reporting include: Conducting follow-up interviews with physicians, employers, and workers; investigating work sites; delivering technical assistance regarding exposure reduction or prevention; providing referrals for consultation and enforcement; and developing and disseminating educational materials and outreach programs. To coordinate their reporting and intervention activities for maximum efficiency, state ABLES programs are strongly encouraged to develop effective working relationships with the childhood lead prevention programs in their states. An estimated 2%–3% of children with BLLs ≥10 μ/dL reach those levels from exposure to lead brought home from the workplace on the clothes or in the vehicles of their adult caregivers.

ABLES is being included for the first time under this OMB approval request. ABLES is also a state laboratory-based surveillance system and many states collect both child and adult blood lead data. This request is for a 3-year extension with a change in the burden hours and inclusion of the adult blood lead surveillance system. There is no cost to respondents.

Respondents	Number of respondents	Number of responses per respondent	Average burden per response (in hrs.)	Total burden hours
State and Local Health Departments for Child Surveillance	47	4	2	376
State and Local Health Departments for Adult Surveillance	37	4	2	296
Total				672

Dated: June 21, 2004.

Diane Allen,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 04–14669 Filed 6–28–04; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[CMS–5025–N]

RIN 0938–ZA51

Medicare Program; Medicare Replacement Drug Demonstration

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

ACTION: Notice.

SUMMARY: This notice announces the implementation of a demonstration that would pay through December 31, 2005 under Medicare Part B for drugs and biologicals that are prescribed as replacements for existing covered Medicare drugs and biologicals described in section 1861(s)(2)(A) or 1861(s)(2)(Q), or both, of title XVIII of the Social Security Act. Under this demonstration certain self-injected or oral drugs that are not normally covered under Medicare Part B would be covered if they were a replacement for a non self-administered drug or biological normally provided in a physician's office. The statute requires cost sharing in the same manner as Medicare Part D. No more than 50,000 patients may be covered under the demonstration and total funding is limited to $500 million.

ADDRESSES: *Mail:* Written inquiries regarding this demonstration must be submitted by mail to the following address: Centers for Medicare & Medicaid Services, Attn: Jody Blatt, Division of Payment Policy Demonstrations, Office of Research, Development, and Information, Centers for Medicare & Medicaid Services, C4–15–27, 7500 Security Boulevard, Baltimore, Maryland 21244–1850. Please allow sufficient time for mailed information to be received in a timely manner in the event of delivery delays.

E-mail: Inquiries may be sent to the following e-mail address: *Section641demo@cms.hhs.gov*. Because of staffing and resource limitations, we cannot accept applications by facsimile (FAX) transmission.

FOR FURTHER INFORMATION CONTACT: Jody Blatt, (410) 786–6921 or *Section641Demo@cms.hhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Section 641 of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (MMA) (Pub. L. 108–173) provides for a demonstration that would pay under Medicare Part B for drugs and biologicals that are prescribed as replacements for existing covered Medicare drugs and biologicals described in section 1861(s)(2)(A) or 1861(s)(2)(Q), or both, of title XVIII of the Social Security Act (the Act).

For example, under this demonstration certain oral or self-injected drugs that are not normally covered under Medicare Part B would be covered if they were a replacement for a non-self-administered drug or biologic that is normally provided in a physician's office or an oral chemotherapeutic drug or biologic agent that is currently covered by Medicare under Part B. The legislation requires cost sharing in the same manner as Medicare Part D. No more than 50,000 patients may be covered under the demonstration and total funding is limited to $500 million. The demonstration is to commence with the acceptance of applications in July 2004 for coverage starting in September or October 2004. The demonstration will terminate December 31, 2005. In 2006, these drugs will be covered under Part D of Medicare for all those beneficiaries who elect to enroll in Part D.

II. Provisions of the Notice

A. Covered Drugs

In order to determine what drugs shall be covered under the demonstration, we established an inter-agency panel of clinicians to determine the criteria for defining what constitutes a "replacement" drug as provided in section 641 of the MMA. An initial set of criteria were shared with the public at an Open Door Forum held at CMS. Based on feedback received at this forum and subsequently in writing, the criteria have been modified. We are adopting the criteria proposed by this interagency panel as modified and have determined that, to be covered under this demonstration, a drug/biological must meet all of the following criteria:

1. A drug or biological covered under this demonstration must meet the statutory requirement of being a replacement by eliminating the concurrent need for a currently covered drug or biological for a currently covered indication.

2. Coverage of the drug or biological in the demonstration is limited to FDA approved indications and, for any drug with an existing FDA approved indication, any additional indication if such additional indication is being reviewed by the FDA; and the requester has received documentation from the FDA that no filing issues remain.

3. The drug must be at least of equal efficacy to the covered drug for which it is a replacement.

4. Use of the drug represents an advantage in terms of access and/or convenience for patients compared to the currently covered drug.

5. Drugs are not eligible for coverage under this demonstration if the drug they are replacing is not commonly provided incident to a physician service (for example, anti-hypertensives, antibiotics, oral hypoglycemics, etc.).

These criteria are consistent with the statutory requirement under section 641(a) of the MMA that the demonstration include only drugs and biologicals that are replacements for drugs currently covered under Part B. Although the statute does not explicitly require us to cover all drugs and biologicals prescribed as replacements for drugs currently covered under Part B, we nevertheless considered doing so. However, in light of the legislative directives limiting funding for the demonstration to $500 million and enrollment in the demonstration to 50,000 beneficiaries, we concluded that this demonstration's limited resources should be allocated so as to maximize the aggregate benefit to the Medicare population. We believe the criteria set forth above achieves this by focusing resources on those drugs or biologicals that have proven efficacy for the conditions indicated as well as significantly improve access to important medications for severely ill beneficiaries. Using these criteria, we have identified the following drugs/biologicals as covered under this demonstration for the following conditions:

DRUGS COVERED UNDER THE MEDICARE REPLACEMENT DRUG DEMONSTRATION

Demonstration covered indication	Drug/biological—compound name (brand name)
Rheumatoid Arthritis	Adalimumab (Humira).
	Anakinra (Kineret).
	Etanercept (Enbrel).
Multiple Sclerosis	Glatiramer acetate (Copaxone).
	Interferon beta—1a (Rebif, Avonex).
	Interferon beta—1b (Betaseron).
Osteoporosis (patient must be homebound)	Calcitonin—nasal (Miacalcin—nasal).
Pulmonary Hypertension	Bosentan (Tracleer).
Secondary Hyperparathyroidism	Doxercalciferol (Hectoral).
Paget's Disease	Alendronate (Fosamax).
	Risedronate (Actonel).
Hepatitis C	Pegylated interferon alfa-2a (Pegasys).
	Pegalated interferon alfa-2a (PEG-Intron).
CMV Retinitis	Valcyte (Valganciclovir).
Anti-Cancer	
Cutaneous T-cell Lymphoma	Bexarotene (Targretin).
Non-small cell lung cancer	Gefitinib (Iressa).
Epithelial ovarian cancer	Altretamine (Hexalen).
Chronic Myelogenous Lymphoma	Imatinib Mesylate (Gleevec).
GI Stromal Tumor	Imatinib Mesylate (Gleevec).
Anaplastic astrocytoma	Temozolomide (Temodar).
Multiple Myeloma	Thalidomide (Thalomid).
Breast Cancer	Hormonal therapy.
Stage 2–4 only	Anastrozole (Arimidex).
	Exemestane (Aromasin).

DRUGS COVERED UNDER THE MEDICARE REPLACEMENT DRUG DEMONSTRATION—Continued

Demonstration covered indication	Drug/biological—compound name (brand name)
	Letrozole (Femara). Tamoxifen (Nolvadex). Toremifene (Fareston).

We will consider covering additional drugs if they meet the criteria specified above and if the enrollment and/or funding limit for the demonstration has not been reached or is projected to be reached before the end of the demonstration.

If you believe that another drug/biological should be considered for coverage under this demonstration, please submit your request, along with all required supporting documentation, in writing as specified below.

Requests for consideration must explicitly list the drug/biological to be covered (trade and generic names), manufacturer, FDA approved indication(s), intended disease(s) and/or patient populations for the demonstration project (including a reference to the applicable treatment guideline, for example, the National Comprehensive Cancer Network (NCCN) guideline), typical dosing pattern in each relevant patient population, the Part B covered drug/biological that will be replaced, and how it meets each of the criteria noted above. Additionally, you must submit information describing the projected average annual cost of the medication following typical dosing patterns and any savings that Medicare might realize as a result of using this drug/ biological as a replacement. Those requesting inclusion of a drug or biological that has not yet received FDA approval for the proposed indication but otherwise meets all of the criteria must submit a letter from the FDA verifying that the FDA has received all of the data it needs to complete its review and that no further filing issues remain.

B. Implementation

We have entered into a contract with TrailBlazer Health Enterprises, L.L.C. (TrailBlazer) to handle eligibility determination, enrollment and claims processing for this demonstration. Under this arrangement, TrailBlazer will subcontract with Advance PCS, a Caremark Company (Caremark), to provide pharmacy benefit management (PBM) services.

Starting July 6, 2004, TrailBlazer will begin accepting applications to participate in this demonstration. Applications may be downloaded from our Web site: *http://www.cms.hhs.gov/researchers/demos/drugcoveragedemo.asp* or obtained by calling 1–866–563–5386 any time after 8 a.m. Eastern time on July 6, 2004. Calls prior to that time will not be accepted. Applications must be received by 5 p.m. Eastern time September 30, 2004. Applications received by August 16, 2004 will be eligible for an early selection process for coverage under the demonstration effective September 1, 2004.

Applications will be considered under two categories: (1) Those seeking coverage for a covered cancer drug and (2) those seeking coverage for any other replacement drug covered under the demonstration. The purpose of creating two enrollment categories is to insure that at least 40 percent of the available funding goes toward oral cancer treatments as specified in the Medicare Modernization Act of 2003 "Conference Agreement." If more persons submit applications than we believe we can accommodate because of the limits for either or both of the enrollment categories specified, participants will be chosen on a random basis among all completed applications received. Notification to applicants of their status regarding participation in the demonstration will be sent out by October 13, 2004. For those participating in the demonstration, coverage will be effective October 18, 2004.

If fewer applications are received than the maximum number of enrollees permitted or than can be covered within the projected funding limits, then all eligible beneficiaries who have submitted applications by the deadline will be enrolled in the demonstration with an effective date of October 18, 2004. To the extent that enrollment slots remain unfilled and we project available funding for additional participants, additional applications will be considered on a rolling basis after that date, although we do not anticipate this will occur.

Those selected to participate will receive a "welcome packet" from Caremark including information on how to fill their prescriptions as well as supplemental information about their demonstration pharmacy benefit.

C. Eligibility

In order to be eligible for participation in this demonstration, a beneficiary must meet the following criteria:

- The beneficiary must have Part A and Part B.
- Medicare must be the beneficiary's primary health insurance.
- The beneficiary must reside in one of the 50 states or the District of Columbia.

Beneficiaries who are members of Medicare Advantage or other Medicare coordinated care health plans as well as those covered under the traditional Medicare Fee-For-Service program are eligible to enroll.

Because a primary purpose of this demonstration is to increase access to important medications in advance of the full implementation of the Medicare Part D drug benefit in 2006, those beneficiaries who already have a comprehensive drug coverage plan will not be eligible to enroll. This includes beneficiaries who are covered under Tricare, the PACE program under section 1894 of the Act, and most Medicaid and SCHIP plans, as well as those who are covered under a comprehensive Medicare Advantage plan or an employer or union sponsored retiree plan. However, beneficiaries without any drug coverage and beneficiaries with more limited drug coverage, such as that offered by Medicare supplemental (employer-sponsored prescription drug coverage (or other alternative coverage)) plans and some Medicare Advantage or other Medicare coordinated care health plans, are eligible to apply for participation. Beneficiaries who are eligible for VA benefits are also eligible to apply for this demonstration if they do not use their VA benefits to pay for medications. Beneficiaries with questions about eligibility may contact 1–866–563–5386. Beneficiaries who have a Medicare sponsored discount drug card may participate in the demonstration, but they may not use the card to pay for drugs or biologicals covered under the demonstration. A separate demonstration specific card will be issued to beneficiaries participating in this demonstration.

In order to apply for this demonstration, a beneficiary must obtain certification from their physician stating that the beneficiary (1) has a medical condition for which coverage of the demonstration drug is allowed under the demonstration and (2) either the physician has already written a prescription for the demonstration drug for the beneficiary or intends to do so if the beneficiary is enrolled in the demonstration. The beneficiary does not need to be taking either the demonstration drug or a specific Medicare Part B covered drug in order to be eligible for this demonstration. Beneficiaries who are newly diagnosed and/or for whom the covered drug is prescribed for the first time during the course of the demonstration may apply at that time and will be considered for participation in the demonstration to the extent new applications can be considered.

Beneficiaries who participate in the demonstration will retain all of their Medicare benefits and should follow their physician's guidance regarding any changes in medication and/or treatment that may be medically appropriate.

D. Beneficiary Cost Sharing

In accordance with the requirements of section 641 of the MMA, cost sharing under this demonstration must be applied in the same manner as the standard prescription drug benefit under Part D that will be effective in 2006, as described in section 1860D–2(b) of the Social Security Act (the "Act"). However, because this demonstration will not begin covering benefits until September, beneficiary out-of-pocket cost sharing for 2004 will be pro-rated to approximately one-third of the standard amount to reflect the reduced benefit year. In 2005, the full standard cost-sharing amount will be applied.

Therefore, while beneficiaries will not be required to pay a premium for participating in the demonstration, they will be required to meet an annual deductible before benefits are paid. This deductible will be applied each calendar year a beneficiary is covered, regardless of when the beneficiary enrolls in the demonstration.

In 2005, a standard annual deductible of $250 will be applied. After the annual deductible has been reached, the beneficiary must pay 25 percent coinsurance for the cost of each prescription until the beneficiary has received covered replacement drugs totaling $2,250, which includes amounts paid out of pocket by the beneficiary (the $250 deductible plus $500 worth of "25% coinsurance" for a total of $750) and amounts paid by Medicare under this demonstration. Once the beneficiary has received $2,250 in replacement drugs, the beneficiary will be responsible for paying 100 percent of all costs of the covered replacement drug until the beneficiary has paid an additional $2,850 for a total of $3,600 out-of-pocket. Covered replacement drug costs paid by an individual (such as a family member) or a state pharmacy assistance plan on the beneficiary's behalf, and low-income assistance paid by Medicare under the demonstration on behalf of beneficiaries eligible for such assistance (see II E. below), count toward the beneficiary's $3,600 "out-of-pocket limit". Under the demonstration, in some cases, funds provided by charitable organizations may also count toward the beneficiary's out-of-pocket limit. However, costs for which the beneficiary is reimbursed through insurance or otherwise, a group health plan, or other third-party payment arrangement do not count toward the $3,600 out-of-pocket limit. Once the $3,600 "out-of-pocket limit" has been reached, the beneficiary will pay the greater of 5 percent of the cost of the covered replacement drug or a fixed co-payment of $2 for generic or preferred brand drugs that are multiple source drugs (as defined in section 1927(k)(7)(A)(i)) or $5 for all other drugs.

As noted above, due to fact that the demonstration is not starting in 2004 until approximately two-thirds of the calendar year has passed, out-of-pocket costs for beneficiaries who enroll in 2004 will be reduced by approximately two-thirds. The annual deductible will be reduced from $250 to $85. This deductible will be applied regardless of when in 2004 a beneficiary enrolls. Once the beneficiary has met the deductible, s/he will pay 25% of the next $660 in allowable costs until s/he has paid an additional $165 out-of-pocket. The beneficiary will then be responsible for paying 100 percent of the allowed cost of the covered replacement drug until the beneficiary has paid an additional $950 for a total of $1,200 out-of-pocket ($85 deductible plus $165 at the 25% coinsurance level plus $950 at the 100% coinsurance level). The table below summarizes the out-of-pocket costs under the demonstration for 2004 and 2005.

	2004 (Sept–Dec)	2005 (Jan–Dec)
Deductible		
Standard Benefit*	• $85	• $250
25% Coinsurance Range		
• Allowable Cost of Drugs	• 660	• 2,000
• 25% Out of Pocket	• 165	• 500
100% Coinsurance "Donut"		
• 100% Out-of-Pocket Payments (in addition to above)	• 950	• 2,850
Catastrophic Limit		
1. Total Allowable Cost of Drugs	• 1,695**	• 5,100**
2. Total Out of Pocket Payments	• 1,200	• 3,600

*Some low-income beneficiaries, those with incomes between 135% and 150% of the Federal Poverty Level, will also have the deductible reduced from $50 to $20 in 2004. Other low-income beneficiaries will not pay any deductible in either year.

**Because beneficiary cost-sharing under the demonstration that is paid for by a group health plan, insurer or otherwise, or similar third party payment arrangement will not count toward the annual out-of-pocket limit, the total drug spending amount that triggers catastrophic coverage may be higher for beneficiaries with these alternative sources of coverage.

Beneficiaries may receive their drugs on a retail or mail order basis, but must get them through Caremark, the pharmacy benefit manager contracting with TrailBlazer to implement this demonstration. Caremark has a national network of pharmacies. More specific information about the network and pharmacies available can be obtained by calling 1–866–563–5386. Upon enrolling in the demonstration, beneficiaries will be mailed a complete package of information, including a demonstration identification card and instructions on how to fill their prescriptions for the demonstration-covered drug. This card may be used only for drugs covered under the demonstration.

E. Low-Income Assistance

Beneficiaries who meet the criteria specified in Part D, section 1860D–14 of the Act, for low-income assistance will be eligible for assistance under this demonstration. Tables 1A and 1B specify the different cost sharing requirements for the standard benefit level as well as the different low-income options for 2004 and 2005. Table 2 identifies which benefit levels apply based on a person's annual income and available financial resources.

Beneficiaries, or their authorized representatives, will be required to submit an application form attesting to the beneficiary's annual income and financial resources in order to be considered for the subsidy.

F. Application Instructions

Starting on or before July 6, 2004, application forms will be available from our Web site: *http://www.cms.hhs.gov/researchers/demos/drugcoveragedemo.asp*. Alternatively, individuals may call 1–866–563–5386 (TTY: 1–866–5387) any time after 8 a.m. Eastern time on July 6, 2004 to have an application mailed to them. Calls prior to that time will not be accepted.

Applications must be received by TrailBlazer by 5 p.m. eastern time, September 30, 2004. Applications should be sent to the following address: Medicare Replacement Drug Demonstration, c/o TrailBlazer Health Enterprises, L.L.C., P.O. Box 5136, Timonium, MD 21094.

The application form consists of two parts. Both parts must be filled in completely and submitted by September 30, 2004 in order to be considered for the demonstration.

The first part of the form requests basic demographic information, information on the drug being requested and the availability of alternative insurance coverage for prescription drugs. Because this demonstration is intended to increase access to prescription drugs, beneficiaries who have comprehensive, alternative drug coverage through Medicaid, SCHIP, the PACE program under section 1894 of the Act, Tricare, retiree insurance, or other source are not eligible to enroll. However, beneficiaries who have more limited drug coverage such as under a Medicare supplement (employer-sponsored prescription drug coverage (or other alternative coverage, including Medigap plans)) plan are eligible to enroll. Beneficiaries who are enrolled in a Medicare Advantage or other Medicare coordinated care health plan are also eligible to enroll if they do not have comprehensive drug coverage under that plan that would cover the replacement drug.

The second part of the application form is a certification from the physician who is prescribing the replacement drug for the beneficiary. The physician must submit this signed statement specifying that he (or she) is prescribing or will be prescribing the medication for the covered condition.

Beneficiaries who believe they qualify for low-income assistance (see II.E above) must also complete and sign an attestation of income and resources. The rules for low-income assistance, including coverage levels and determination of eligibility, have been established to be consistent with what will be in effect in 2006 when the Medicare Part D drug benefit is implemented. Information submitted on the application for low-income assistance is subject to formal verification by CMS. Enrollment in the demonstration will be determined on a "need-blind" basis, that is, without regard to whether a beneficiary has also submitted an application for the low-income subsidy. Moreover, applications for the low-income subsidy may be submitted at any time during the duration of the demonstration and will be considered as long as funds are available. However, the low-income subsidy will not be provided retroactively.

G. Submission of Written Materials

Those wishing to propose additional drugs/biologicals to be considered for coverage under the demonstration must submit written information documenting how the proposed drug meets the criteria specified in section II(A) of this notice. While the format for this information is not prescribed, we are requesting that all of the criteria listed above be fully addressed in the materials submitted.

Written materials may be submitted by mail or e-mail to the addresses listed above under "Inquiries, Registration and Submission of Information."

BILLING CODE 4120–01–P

TABLE 1A – MEDICARE REPLACEMENT DRUG DEMONSTRATON – OUT-OF-POCKET COSTS FOR CY 2004

Benefit Categories ⟶	Benefit Level 1 (Standard)	Benefit Level 2	Benefit Level 3	Benefit Level 4	Benefit Level 5
Deductible	$85	$20	$0	$0	$0
After the annual deductible, you pay this amount for each prescription until you have paid a total of $1,200 out of pocket[1]:	▪ 25% coinsurance until you have paid $165 in additional out of pocket costs and then, ▪ 100% of all costs until your total out of pocket costs = $1,200(that is, the next $950 in allowable costs out-of-pocket)	▪ 15% coinsurance	▪ A fixed co-payment of $2 for generic or preferred multi-brand drugs or $5 for all other drugs	▪ A fixed co-payment of $1 for generic or preferred multi-brand drugs or $3 for all other drugs	You pay nothing
Once you have paid $1,200 in total out of pocket costs, you pay this amount for each prescription:	The greater of: ▪ 5% or ▪ A fixed co-payment of $2 for generic or preferred multi-brand drugs or $5 for all other drugs	You pay: ▪ A fixed co-payment of $2 for generic or preferred multi-brand drugs or $5 for all other drugs	You pay nothing	You pay nothing	You pay nothing

[1] Any amount paid by other insurance, with the exception of a State pharmacy assistance program or certain charitable organizations may NOT be counted toward you out-of-pocket limit.

TABLE 1B – MEDICARE REPLACEMENT DRUG DEMONSTRATON – OUT-OF-POCKET COSTS FOR CY 2005

Benefit Categories ⟶	Benefit Level 1 (Standard)	Benefit Level 2	Benefit Level 3	Benefit Level 4	Benefit Level 5
Deductible	$250	$50	$0	$0	$0
After the annual deductible, you pay this amount for each prescription until you have paid a total of $3,600 out of pocket[1]:	▪ 25% coinsurance until you have paid $500 in additional out of pocket costs and then, ▪ 100% of all costs until your total out of pocket costs = $3,600 (that is, the next $1,350 in allowable costs out of pocket)	▪ 15% coinsurance	▪ A fixed co-payment of $2 for generic or preferred multi-brand drugs or $5 for all other drugs	▪ A fixed co-payment of $1 for generic or preferred multi-brand drugs or $3 for all other drugs	You pay nothing
Once you have paid $3600 in total out of pocket costs, you pay this amount for each prescription:	The greater of: ▪ 5% or ▪ A fixed co-payment of $2 for generic or preferred multi-brand drugs or $5 for all other drugs	You pay: ▪ A fixed co-payment of $2 for generic or preferred multi-brand drugs or $5 for all other drugs	You pay nothing	You pay nothing	You pay nothing

[1] Any amount paid by other insurance, with the exception of a State pharmacy assistance program or certain charitable organizations, may NOT be counted toward you out-of-pocket limit.

TABLE 2 – BENEFIT CATEGORIES APPLICABLE BASED ON ANNUAL INCOME AND FINANCIAL ASSETS

If your Income Is: / And Your Total Assets are	Less than: ▪ $6000 for an individual, or ▪ $9000 for a couple	Between ▪ $6000 and $10,000 for an individual, or ▪ $9000 and $20,000 for a couple	Over ▪ $10,000 for an individual, or ▪ $20,000 for a couple
Less than 100% of the Federal Poverty Level (FPL) AND you are a full benefit dual Medicare and Medicaid eligible beneficiary (1)(2)	Benefit Level 4	Benefit Level 4	Benefit Level 4
100% or more than the Federal Poverty Level (FPL) AND you are a full benefit dual Medicare and Medicaid eligible beneficiary (1)(2)	Benefit Level 3	Benefit Level 3	Benefit Level 3
Less than 135% of the FPL and you are not a full benefit dual Medicare and Medicaid eligible beneficiary	Benefit Level 3	Benefit Level 2	Benefit Level 1
135% or more of the FPL but less than 150% of the FPL and you are not a full benefit dual Medicare and	Benefit Level 2	Benefit Level 2	Benefit Level 1
150% or more of the FPL and you are not a full benefit dual Medicare and	Benefit Level 1	Benefit Level 1	Benefit Level 1

NOTES: (1) Institutionalized full benefit dual Medicare and Medicaid eligible beneficiaries will be covered under **Benefit Level 5** (See Tables 1A and 1B).

(2) Most full benefit dual Medicare and Medicaid eligible beneficiaries receive a comprehensive drug benefit through the Medicaid program. Only beneficiaries who do not already have a comprehensive drug benefit through their Medicaid program are eligible to participate in this demonstration.

TABLE 3 – FEDERAL POVERTY LEVEL GUIDELINES FOR 2004

	100 % of Federal Poverty Level		135% of Federal Poverty Level		150% of Federal Poverty Level	
	Individual	**Couple**	**Individual**	**Couple**	**Individual**	**Couple**
Lower 48 States	$9,310	$12,490	$12,569	$16,862	$13,965	$18,735
Alaska	$11,630	$15,610	$15,701	$21,074	$17,445	$23,415
Hawaii	$10,700	$14,360	$14,445	$19,386	$16,050	$21,540

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III. Collection of Information Requirements

Under the Paperwork Reduction Act of 1995, we are required to 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 must be approved by OMB, section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995 requires that we solicit comment on the following issues:

• The need for the information collection and its usefulness in carrying out the proper functions of our agency.

• The accuracy of our estimate of the information collection burden.

• The quality, utility, and clarity of the information to be collected.

• Recommendations to minimize the information collection burden on the affected public, including automated collection techniques.

Due to the following reasons, CMS requested that OMB grant OMB emergency approval of the collection requirements associated with this demonstration Section 641 of the MMA: (1) The statute required that this demonstration begin 90 days after passage of the legislation, which was March 8, 2004; (2) due to the complexities of implementing this demonstration, CMS was unable to meet that deadline; and (3) because of the importance of this demonstration to beneficiaries with serious illnesses and the already delayed time frame, it was urgent that there not be further delays.

Based on the justification referenced above for emergency approval, with OMB concurrence, on May 19, 2004 Volume 69, Number 97, Pages 28894–28895, CMS announced the initiation of procedural requirements set forth in 5 CFR 1320.13 to facilitate compliance with Chapter 25 of Title 44 of United States Code. As the result, the collection requirements associated with this demonstration, "Application for Participation in Medicare Replacement Drug Demonstration", were approved under OMB control number 0938–0924.

It should be noted that during the 180-day emergency approval period, CMS will publish a **Federal Register** notice announcing the initiation of an extensive 60-day public comment period on these requirements. Upon completion of the 60-day comment period, we will submit the requirements for OMB review and an extension of this emergency approval.

Authority: Section 641 of the Medicare Prescription Drug Improvement and Modernization Act of 2003.

(Catalog of Federal Domestic Assistance Program No. 93.778 and No. 93.774, Medicare—Supplementary Medical Insurance Program)

Dated: June 4, 2004.

Mark B. McClellan,

Administrator, Centers for Medicare & Medicaid Services.

[FR Doc. 04–14673 Filed 6–24–04; 3:00 pm]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket Nos. 1976N–0080 and 2000N–1610]

Prescription Drug Products; Digoxin Elixir; Extension to Obtain Marketing Approval

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that it will continue to exercise enforcement discretion to assure the continued availability of digoxin elixirs after June 28, 2004, allowing manufacturers to continue to market these products without approved applications until December 28, 2004. FDA is granting this extension to give manufacturers of digoxin elixir additional time to obtain marketing approval and bring products to market.

DATES: The date by which manufacturers must obtain marketing approval is extended to December 28, 2004.

FOR FURTHER INFORMATION CONTACT: Mary E. Catchings, Center for Drug Evaluation and Research (HFD–7), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–594–2041.

SUPPLEMENTARY INFORMATION: In the **Federal Register** of June 26, 2002 (67 FR 42992), FDA published a final rule revoking § 310.500 (21 CFR 310.500), which established conditions for marketing digoxin products for oral use (tablets and elixir). The agency concluded that § 310.500 was no longer necessary because the products, which are new drugs, can be regulated under the approval process for new drug applications and abbreviated new drug applications as set forth in the Federal Food, Drug, and Cosmetic Act (the act). Previously, in the **Federal Register** of November 24, 2000 (65 FR 70573), we reaffirmed the new drug status of oral digoxin products and announced that these products required approved applications for marketing.

The June 26, 2002, final rule advised that manufacturers who were marketing digoxin elixir drug products on or before June 26, 2002, may continue to market their products until June 28, 2004.[1] The final rule stated that a manufacturer who marketed a digoxin elixir drug product without an approved application after that date would be subject to regulatory action.

We permitted this period of continued marketing because we regard digoxin elixir products as medically necessary and, therefore, wanted to allow sufficient time for manufacturers to conduct the required studies and to prepare and submit applications, as well as to allow the agency sufficient time to review these applications. It now appears that as of June 28, 2004, there may not be any manufacturers prepared to market digoxin elixir under an approved application. To assure the continued availability of digoxin elixirs after June 28, 2004, we have decided to extend for 6 months, until December 28, 2004, the date by which manufacturers must obtain marketing approval. This extension will only apply to manufacturers who have submitted applications to FDA and who continue to pursue approval of their applications with due diligence. We will reexamine the need for a continued exercise of enforcement discretion at the end of this 6-month period. In making this determination, we will consider whether there is an approved digoxin elixir product on the market and whether the manufacturer is capable of producing sufficient product to meet patient needs.

This notice is issued under sections 502 and 505 of the act (21 U.S.C. 352, 355)) and under authority delegated to the Associate Commissioner for Policy and Planning (21 CFR 5.20).

Dated: June 24, 2004.

Jeffrey Shuren,

Assistant Commissioner for Policy.

[FR Doc. 04–14796 Filed 6–25–04; 2:57 pm]

BILLING CODE 4160–01–S

[1] After June 26, 2002, a new digoxin elixir drug product could not be introduced into the market unless we had approved an application for that product.

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 2003D–0554]

Compliance Policy Guide Regarding Prior Notice of Imported Food Under the Public Health Security and Bioterrorism Preparedness and Response Act of 2002; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of a revised Compliance Policy Guide (CPG) Sec. 110.310 entitled "Prior Notice of Imported Food

Under the Public Health Security and Bioterrorism Preparedness and Response Act of 2002." The original CPG, which was published in the **Federal Register** of December 15, 2003 (68 FR 69708), provides written guidance to FDA's and Customs and Border Protection's (CBP's) staff on enforcement of section 307 of the Public Health Security and Bioterrorism Preparedness and Response Act of 2002 (the Bioterrorism Act) and the agency's implementing regulations, which require prior notice for all food imported or offered for import into the United States. The CPG has been revised to provide additional guidance to FDA and CBP staff regarding how to address food that is imported or offered for import for noncommercial purposes with a noncommercial shipper. The revised CPG also reflects a change in the date of Stage III enforcement guidance for the interim final rule from May 13, 2004, to June 4, 2004.

DATES: This guidance is final upon the date of publication. However, you may submit written or electronic comments at any time.

ADDRESSES: Submit written requests for single copies of the guidance to the Division of Compliance Policy (HFC–230), Office of Enforcement, Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857. Send one self-addressed adhesive label to assist that office in processing your request or include a fax number to which the guidance may be sent.

Submit written comments on the guidance to the Division of Dockets Management, 5630 Firhers Lane, rm. 1061, Rockville, MD 20852. Submit electronic comments to *http://www.fda.gov/dockets/ecomments.* See the **SUPPLEMENTARY INFORMATION** section for electronic access to the guidance document.

FOR FURTHER INFORMATION CONTACT: Domenic Veneziano, Office of Regulatory Affairs (HFC–100), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 703–621–7809.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of revised CPG Sec. 110.310 entitled "Prior Notice of Imported Food Under the Public Health Security and Bioterrorism Preparedness and Response Act of 2002." This revised guidance is issued with CBP concurrence and explains to FDA and CBP staff the new FDA and CBP policies on enforcement of section 307 of the Bioterrorism Act and its implementing regulations, which require prior notice to FDA of all food imported or offered for import into the United States (68 FR 58974, October 10, 2003 (codified at 21 CFR 1.276 through 1.285)). FDA has revised the original CPG, which was published on December 15, 2003 (68 FR 69708), to include additional guidance regarding food imported or offered for import for noncommercial purposes with a noncommercial shipper. The CPG explains that a "non-commercial purpose" generally exists when the food is purchased or otherwise acquired by an individual for nonbusiness purposes and the shipper is the individual (i.e., the individual delivers the food to a post office or common carrier for delivery to self, family member, or friend for nonbusiness purposes, i.e., not for sale, resale, barter, business use, or commercial use). With respect to these food imports, FDA intends to focus its efforts on education through March 2005 (or shortly thereafter, depending on the date of issuance of the final rule). Examples of foods imported or offered for import that may be covered by this noncommercial category include the following:

- Food in household goods, including military, civilian, governmental agency, and diplomatic transfers;
- Food purchased by a traveler and mailed or shipped to the traveler's U.S. address by the traveler;
- Gifts purchased at a commercial establishment and shipped by the purchaser, not the commercial establishment. The revised CPG also corrects the date of Stage III enforcement guidance for the interim final rule from May 13, 2004, to June 4, 2004, per the Automated Broker Interface (ABI) Administrative Message 04–1406 issued by CBP on June 3, 2004.

FDA is issuing this document as level 1 guidance consistent with FDA's good guidance practices regulation § 10.115 (21 CFR 10.115). The revised CPG Sec. 110.310 is being implemented immediately without prior public comment, under § 10.115(g)(2), because the agency has determined that prior public participation is not feasible or appropriate. Under section 307 of the Bioterrorism Act, the prior notice requirements were effective December 12, 2003, making it urgent that the agencies explain how they intend to enforce those requirements. Moreover, as a result of the revision to the CPG, FDA's policies are generally less burdensome for food imported or offered for import for noncommercial purposes with a noncommercial shipper.

II. Comments

Interested persons may submit to the Division of Dockets Management (see **ADDRESSES**) written or electronic comments on the guidance document. Submit two copies of written comments, except that individuals may submit one copy. Comments are to be identified with the docket number found in brackets in the heading of this document. The guidance and received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

III. Electronic Access

An electronic version of this guidance is available on the Internet at *http://www.fda.gov/ora* under "Compliance References."

Dated: June 24, 2004.

John M. Taylor,

Associate Commissioner for Regulatory Affairs.

[FR Doc. 04–14766 Filed 6–25–04; 9:17 am]

BILLING CODE 4160–01–S

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Indian Health Service

Epidemiology Grant Program for American Indians/Alaska Natives; Notice of Competitive Cooperative Agreement Applications

Funding Opportunity Number: HHS–IHS–EPID–2004–0001.

CFDA Number: 93.231.

Dates:

Application Deadline: July 30, 2004.

Application Review: August 16, 2004.

Applicants Notified of Results: On or about September 1, 2004 (approved, recommended for approval but not funded, or disapproved).

Anticipated Award Start Date: September 15, 2004.

I. Funding Opportunity Description

The Indian Health Service (HHS) announces that competitive cooperative agreement applications are now being accepted for the Epidemiology Grant Program for American Indians/Alaska Natives and Urban Indian communities. These cooperative agreements are established under the authority of section 214(a)(1) of the Indian Health Care Improvement Act, Pub. L. 94–437, as amended by Pub. L. 102–573. There will be only one funding cycle during Fiscal Year (FY) 2004. These cooperative agreements will be awarded and administered in accordance with this announcement, Department of Health and Human Service (HHS) at 45

CFR part 92, HHS Uniform Administrative Requirements for Grants and Cooperative Agreements to State, local, and tribal governments, or 45 CFR part 74, Uniform Administrative Requirements for Awards and Subawards to Institutions of Higher Educations, Hospitals, Other Nonprofit Organizations, and Commercial Organizations; the Public Health Service (PHS) Grant Policy Statement; and applicable Office of Management and Budget Circulars.

The PHS urges applicants submitting applications to address specific objectives of *Healthy People 2010*. Interested applicants may obtain a copy of *Healthy People 2010* (Summery Report in print; Stock No. 017–001–00547–9) or CD-ROM (Stock No. 107–001–00549–5) through the Superintendent of Documents, Government Printing Office, P.O. Box 371954, Pittsburgh, Pennsylvania, 15250–7945, or (202) 512–1800. You may access this information via the Internet at the following Web site: *www.health.gov/healthypeople/publications/*.

The purpose of this grant program is to develop Tribal Epidemiology Centers and public health infrastructure through the augmentation of existing programs with expertise in epidemiology and a history of regional support. Activities should include, but not be limited to enhancement of surveillance for disease conditions; epidemiologic analysis, interpretation, and dissemination of surveillance data; investigation of disease outbreaks; development and implementation of epidemiologic studies; development and implementation of disease control and prevention programs; and coordination of activities with other public health authorities in the region. Proposed activities that cover large populations and/or geographical areas that do not necessarily correspond with current IHS administrative areas are encouraged.

In conducting activities to achieve the purpose of this program, the recipient will be responsible for the activities under 1. (Recipient Activities), and IHS will be responsible for conducting activities under 2. (IHS Activities).

1. Recipient Activities

a. Assist AI/AN communities, tribal organizations, and urban Indian organizations in implementing and enhancing disease surveillance systems and identifying their highest priority health status objectives based on epidemiologic data. Collect data relating to, and monitor progress made toward meeting each of the health status objectives of IHS, the AI/AN communities, tribal organizations, and urban Indian organizations in the region. Assist and facilitate reporting of nationally notifiable disease conditions to public health authorities in the region.

b. Participate in the development of systems for sharing, improving, and disseminating aggregate health data at a national level for purposes of advocacy for AI/AN communities, Government Performance Result Act, *Healthy People 2010*, and other national-level activities.

c. Collaborate with national DHHS programs in the development of standardized surveillance and data monitoring methods and data sets.

d. Support responses to public health emergencies in collaboration with the IHS National Epidemiology Program, local, tribal, State, and other Federal health authorities.

e. Develop and implement epidemiologic studies that have practical application in improving the health status of constituent communities. Studies may require Institutional Review Board approval if human subjects are involved.

f. Develop and implement disease control and prevention programs in cooperation with other public health entities. Make recommendations for targeting of public health services needed by constituents.

Ensure the coordination of services and program activities with other similar programs and establish abroad-based council to advise and support the program. Such an advisory council would consist of technical experts in epidemiology and public health, community members, health care providers, and others who could provide overall program direction and guidance.

2. IHS Activities

a. Convene a workshop of funded organizations every year for information-sharing and problem-solving.

b. Provide funded organizations with ongoing consultation and technical assistance to plan, implement, and evaluate each component of the comprehensive program as described under Recipient Activities above. Consultation and technical assistance will include, but not be limited to the following areas:

(1) Interpretation of current scientific literature related epidemiology, statistics, surveillance, *Healthy People 2010* Objectives, and other disease control activities;

(2) Design and implementation of each program component (surveillance, epidemiologic analysis, outbreak investigation, development of epidemiologic studies, development of disease control programs, and coordination of activities); and

(3) Overall operational planning and program management.

Provide opportunities for training fellowships at the Epidemiology Program, IHS, if funds permit.

c. Conduct site visits to assess program progress and mutually resolve problems, as needed, and/or coordinate reverse site visits to IHS in Albuquerque, NM.

d. At the request of the applicant, and if available, assign Federal personnel to a project in lieu of a portion of the financial assistance.

e. Coordinate all epidemiologic activities on a national basis.

II. Award Information

American Indian/Alaska Native tribes, tribal organizations, and eligible intertribal consortia or Indian organizations, may be eligible for a cooperative agreement. Such entities must represent or serve a population of at least 60,000 AI/AN to be eligible. An intertribal consortium or AI/AN organization is eligible to receive a cooperative agreement if it is incorporated for the primary purpose of improving AI/AN health, and it is representative of the tribes, AN villages, or urban Indian communities in which it is located. Collaborations with regional IHS, CDC, State, or university organizations are encouraged (letters of support and collaboration should be included in the application).

The following documentation is required:

1. Tribal Resolution—(a) A signed and dated resolution supportive of the epidemiology cooperative agreement proposal from the Indian tribe(s) served by the project must accompany the application; (b)—applications must include resolutions from all tribes to be served; and (c) applications by tribal organizations will not require a specific tribal resolution(s) if the current blanket tribal resolution(s) under which they operate would encompass the proposed activities and project type.

2. Non-profit organization—copy of 501(c)(3) non-profit certificate.

As part of an effort to establish Epidemiology Centers throughout the nation these funds initially will be used to support activities on a regional basis. Priority will be given to applicants proposing to provide services to large regions consisting of more than a single IHS administrative Area. Priority will also be given to proposals demonstrating evidence of meaningful past and current epidemiologic activities. Collaborative efforts among tribal, local, State, Federal, and university health organizations are encouraged.

It is anticipated that up to approximately $300,000 will be available to fund one award, and if additional funds are identified other awards will be made based on the application scoring level. Although it is expected that project funding needs will vary depending on the scope of work, the anticipated initial funding range, inclusive of direct and indirect costs, is $200,000 to $300,000. If additional funds become available, awardees who were originally funded at levels lower than requested may receive additional funding. Applicants who may be approved but unfunded during the initial round of awards may be eligible for consideration in later funding cycles without further review. At the request of the applicant, Federal personnel, if available, may be assigned to a project in lieu of a portion of the financial assistance. Only one project cooperative agreement will be awarded per Indian tribe or tribal or Indian health organization.

Limitations—only one cooperative agreement project will be awarded per tribe, tribal or Indian organization, or intertribal consortia.

Period of support—Projects will be funded for annual budget periods with project periods of up to two years, dependent upon the scope of work. The continuation years will be based on the following: (1) Satisfactory progress; (2) availability of funds; and (3) continuing need of the IHS for the program.

The projects under this announcement will be awarded as cooperative agreements. Because of the nature of these projects, they will require collaboration with the IHS National Epidemiology Program to: (1) Coordinate activities; (2) participate in projects, investigations, or studies of national scope; and (3) share surveillance and other data collected, in compliance with the Federal Privacy Act, Health Insurance Portability & Accountability Act, or similar tribal laws. The IHS will, therefore, have substantial programmatic involvement in these projects (*see* IHS Activities above).

III. Eligibility Information

1. Eligible Applicants

American Indian/Alaska Native tribes, tribal organizations, and eligible intertribal consortia or Indian organizations, may be eligible for a cooperative agreement. Such entities must represent or serve a population of at least 60,000 AI/AN to be eligible. An intertribal consortium or AI/AN organization is eligible to receive a cooperative agreement if it is incorporated for the primary purpose of improving AI/AN health, and it is representative of the tribes, AN villages, or urban Indian communities in which it is located. Collaborations with regional IHS, CDC, State, or university organizations are encouraged (letters of support and collaboration should be included in application).

2. Cost Sharing or Matching

Cost Sharing or Matching is not required for this application.

IV. Application and Submission Information

1. *Address to Request Application*—An application kit, including the required PHS 5161–1 (Rev. 7/00) (OMB Approval No. 0348–0043) and the U.S Government Standard Forms (SF–424, SF–424A and SF–424B), may be obtained from the grants Management Branch, Division of Acquisition and Grants Operations, IHS, Twinbrook Metro Plaza, Suite 100, 12300 Twinbrook Parkway, Rockville, MD 20852, telephone (301) 443–5204. (The telephone number is not toll-free.)

2. *Content and Form of Application Submission*—All applications must be double-spaced, typewritten, and have consecutively numbered pages using black type not smaller than 12 characters per inch, with conventional one-inch border margins, on only one side of standard size 8.5 x 11 paper that can be photocopied. The application narrative (not incoluding Abstract, Tribal Resolution, Standard Forms, Table of Contents or the Attachments must not exceed 25 typed pages as described above. All applications must include the following in order presented:

- Tribal Resolution(s) and documentation.
- Standard Form 424, Application for Federal Assistance.
- Standard Form 424A, Budget Information—Non-Construction Programs (pages 1 and 2).
- Standard Form 424B, Assurances—Non-Construction Programs (front and back).
- Certification (pages 17–19).
- Checklist (pages 25–26). **Note:** Each standard form and the checklist is contained in the PHS Grant Application, Form PHS 5161–1 (Revised 7/00).
- A one-page project Executive Summary.
- A Table of Contents.
- Introduction and Need for Assistance.
- Project Objective(s), Approach and Results & Benefits.
- Project Evaluation.
- Organizational Capabilities and Qualifications.
- Budget.
- Multi-Year Narratives and Budget Justifications.
- Attachments to include:
- Resumes of key staff.
- Position descriptions for key staff.
- Organizational chart.
- All letters of support from potential collaborators.
- Copy of current negotiated indirect cost rate agreement.
- A map of the area to benefit from the project.
- Application Receipt Card, IH–815–1A.

3. Submission Dates and Times

Application Receipt Date—An original and two copies of the completed grant application must be submitted with all required documentation to the Grants Management Branch, Division of Acquisition and Grants Operations, Twinbrook Metro Plaza, Suite 100, 12300 Twinbrook Parkway, Rockville, Maryland 20852, by close of business July 30, 2004.

Applications shall be considered as meeting the deadline if they are either: (1) Received on or before the deadline with hand carried applications received by close of business 5 p.m.: or (2) postmarked on or before the deadline and received in time to be reviewed along with all other timely applications. A legibly dated receipt from a commercial carrier or the U.S. Postal Service will be accepted in lieu of a postmark. Private metered postmarks will not be accepted as proof of timely mailing. IHS will not acknowledge receipt of applications. Only applications received via the U.S. Postal Service or an overnight shipper, *e.g.*, FedEx, UPS, etc., will be accepted. Late applications not accepted for processing will be returned to the applicant and will not be considered for funding.

4. Intergovernmental Review

Executive Order 12372 requiring intergovernmental review is not applicable to this program.

5. Funding Restrictions

Maximum award amount is $300,000 per year.

6. Other Submission Requirements

Beginning October 1, 2003, applicants were required to have a Dun and Bradstreet (DUNS) number to apply for a grant or cooperative agreement from the Federal Government. The DUNS number is a nine-digit identification number which uniquely identifies business entities. Obtaining a DUNS number is easy and there is no charge.

To obtain a DUNS number, access Dun and Bradstreet online at *http://www.dunandbradstreet.com* or call 1–866–705–5711. Internet applications for a DUNS number can take up to 30 days to process. Interested parties may wish to obtain one by phone to expedite the process. The following information is needed when requesting a DUNS number:

- Organization name.
- Organization address.
- Organization telephone number.
- Name of CEO, Executive Director, President, etc.
- Legal structure of the organization.
- Year organization started.
- Primary business (activity) line.
- Total number of employees.

V. Application Review Information

The instructions for preparing the application narrative also constitute the evaluation criteria for reviewing and scoring the application. Weights assigned each section are noted in parenthesis.

Executive Summary—The Executive Summary may not exceed one typewritten page. It should clearly present the application in summary form, from a "who-what-when-where-how-cost" point of view so that reviewers see how the multiple parts of the application fit together to form a coherent whole.

Table of Contents—Provide a one page typewritten table of contents.

Narrative: Please describe the complete project in clear and succinct language as application reviewers may have little or no knowledge of the Tribe or Tribal organization. It should not exceed 25 double spaced pages, and address the following:

1. Criteria

Introduction, Current Capacity, and Need for Assistance (25 Points)

a. Describe the tribe's current health operation including the population to be served by management of tribal health programs and the number of eligible beneficiaries, whether the tribe has a health department, how long it has been operating, and what programs or services are currently provided. Specifically describe current epidemiologic capacity and history of support for such activities.

b. Provide a precise location of the project and area to be served by the proposed project including a map (include the map in the attachments).

c. Identify the type of project.

d. Explain the reason for the project.

e. Describe the relationship between this project and other federally funded work planned, anticipated, or underway.

f. Identify all previous and/or current TMGs received, dates of funding, and project accomplishments (do not include copies of reports).

Project Objective(s), Approach and Results and Benefits (25 Points)

a. State in measurable and realistic terms the objectives and appropriate activities to achieve each objective for the project.

b. Identify the expected results, benefits, and outcomes or products to be derived from each objective of the project.

c. Include a work plan for each objective that indicates when the objectives and major activities will be accomplished and who will conduct the activities on a calendar time line.

d. If use of consultants or contractors are proposed or anticipated, provide a detailed scope of work that clearly defines the deliverables or outcomes anticipated.

e. Specify who will review and accept the work to be performed by consultants or contractors.

Project Evaluation (10 Points)

a. State how it will be determined if the project's objectives were achieved and how the accomplishment of those objectives can be attributed to the project.

b. Define the criteria to be used to evaluate results and benefits.

c. Explain the methodology that will be used to determine if the needs identified for the project are being met and if the project's outcomes identified are being achieved.

Organization Capabilities and Qualifications (25 points)

a. Explain the management and administrative structure of the organization including documentation of current certified financial management systems from the BIA, IHS, or a Certified Public Accountant and an updated organizational chart (include documentation and the organizational chart in the attachments).

b. Describe the ability of the organization to manage a project of the proposed scope.

c. Provide position descriptions and resumes of key personnel, including those of consultants or contractors in the Appendix. Position descriptions should very clearly describe each position and its duties, indicating desired qualifications and experience requirements related to the project. Resumes should indicate that the proposed staff are qualified to carry out the project activities.

Budget (15 points)

a. Provide a detailed budget for the budget period required.

b. Provide a justification for each line item in the budget including sufficient cost and other details to facilitate the determination of cost allowability and relevance of these costs to the proposed project. The funds requested should be appropriate and necessary for the scope of the project.

c. Describe where the project will be housed, *i.e.*, facilities and equipment available.

d. If indirect costs are claimed, applicant must submit a copy of the Indirect Cost Rate Agreement supporting this claim in the attachments.

Attachments—to include:

- Resumes and job descriptions for key staff.
- Current approved organizational chart.
- Copy of current negotiated indirect cost rate agreement.
- A map of the Area to benefit from the project.
- Application Receipt card, #IHS–815–1A.
- Letters of support/collaboration.

2. Review and Selection Process

Applications submitted by the closing date and verified by the postmark under this program announcement will undergo a review to determine that:

a. The applicant is eligible in accordance with the Eligibility Section of this application.

b. The application executive summary, forms and materials submitted are adequate to allow the review panel to undertake an in-depth evaluation.

c. The application complies with this announcement; otherwise it will be returned without consideration.

Competitive Review of Accepted Applications

Applications meeting eligibility requirements that are complete, responsive, and conform to this program announcement will be reviewed for merit by an Ad Hoc Objective Review Committee (ORC) appointed by the IHS to review and to make recommendations on these applications. The review will be conducted in accordance with the IHS objective review procedures. The technical review process ensures selection of quality projects in a national competition for limited funding. The ORC will include at least 60 percent non-IHS, Federal or non-Federal individuals. Applications will be evaluated and rated on the basis of the application announcement criteria listed above. These criteria are used to evaluate the quality of a proposed project, to assign a numerical score to each application, and to determine the likelihood of its success. Applications will be funded in accordance with scores and funds available.

3. Results of the Review

The results of the objective review are forwarded to the Director, Office of Public Health, for final review and approval. The Director, OPH, will also consider recommendations from the Epidemiology Program and Grants Management Branch. After the Director, OPH, has made decisions on all applications, applicants are notified in writing within approximately 90 days of the closing date. Unsuccessful applicants will be notified in writing of disapproval. A brief explanation of the reasons why the application was not approved will be provided along with the name of the IHS official to contact if more information is desired.

VI. Award Administration Information

1. Award Notices

Successful applicants are notified through the official Notice of Cooperative Agreement (NCA) document. The NCA will state the amount of Federal funds awarded, the purpose of the cooperative agreement, the terms and conditions of the award, the effective date, the project, and budget period.

2. Administration and National Policy Requirements

Cooperative Agreement Administration Requirements: Cooperative agreements are administered in accordance with the following documents:

a. 45 CFR part 92, HHS Uniform Administrative Requirements for Grants and Cooperative Agreements to State, local, and tribal governments or 45 CFR part 74, Uniform Administrative Requirements for Awards and Subawards to Institutions of Higher Education, Hospitals, Other Nonprofit Organizations, and Commercial Organizations;

b. PHS Grants Policy Statement;

c. Appropriate Cost Principles: OMB Circulars A–87 "State and Local Governments," or OMB Circular A–122 "Non-Profit Organizations"; and

d. OMB Circular A–133 "Audits of States, Local Governments, and Non-Profit Organizations."

e. A–102, Grants and Cooperative Agreements with State and Local Governments.

f. A–110; Uniform Administrative Requirements for Grants and Other Agreements with Institutions of Higher Education, Hospitals, and Other Nonprofit Organizations.

3. Reporting Requirements

a. Progress Report—Program progress reports may be required semi-annually. These reports will include a brief description of a comparison of actual accomplishments to the goals established for the period, reasons for slippage, and other pertinent information as required. A final report is due 90 days after expiration of the project/budget period.

b. Financial Status Report—Semi-annually financial status reports will be submitted 30 days after the end of the half year. Final financial status reports are due 90 days after expiration of the project/budget period. Standard Form 269 (long form) will be used for financial reporting.

VII. Agency Contacts

For Epidemiology Program information, contact Dr. James Cheek (*james.cheek@ihs.gov*) or Dr. Nathaniel Cobb (*nathaniel.cobb@ihs.gov*), National Epidemiology Program, Indian Health Service, 5300 Homestead Road, NE., Albuquerque, NM 87110, (505) 837–4132, fax (505) 248–4393. For grant application and business management information, contact Ms. Martha Redhouse, Grants Management Branch, Indian Health Service, Twinbrook Metro Plaza, Suite 100, 123000 Twinbrook Metro Plaza, Rockville, Maryland 20852, (301) 443–5204. (The telephone numbers are not toll-free.)

Dated: June 21, 2004.

Charles W. Grim,

Assistant Surgeon General, Director, Indian Health Service.

[FR Doc. 04–14647 Filed 6–28–04; 8:45 am]

BILLING CODE 4160–16–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Indian Health Service

Special Diabetes Program for Indians Competitive Grant Program; Correction

ACTION: Notice; correction.

SUMMARY: The Indian Health Service published a document in the **Federal Register** on May 28, 2004. The document contained six errors.

FOR FURTHER INFORMATION CONTACT: Denise Clark, Grants Management Branch, Indian Health Service, Reyes Building, 801 Thompson Avenue, Rockville, MD 20852, Telephone (301) 443–5204. (This is not a toll-free number.)

Correction

In the **Federal Register** of May 28, 2004, in FR Doc. 04–12083, on page 30674, in the third column, section I, item 4 under Eligible Applicants, change the 1st sentence to read "SDPI grant recipients and SDPI grant sub-recipients (Tribes who are members of a tribal consortium) are eligible to apply for the SDPI Competitive Grant Program if they are one of the following entities:". On page 30677, in the third column, correct the deadline date of "July 1, 2004" in section B. to read "July 15, 2004". On page 30678, in the first column, section III, item 1 under Eligible Applicants change the 1st sentence to read "Applicants eligible to receive an award under this announcement are SDPI grantees and SDPI grantee sub recipients.". On page 30681, in the second column, Application Due Date, correct "M.D.T." to "E.D.T.". On page 30682, in the first column, under Other Submission Requirements, in the third paragraph, correct the number "222214" to "3". And on page 30682, in the first column, Application Review Information, correct the SF number to read "SF 424".

Dated: June 21, 2004.

Charles W. Grim,

Assistant Surgeon General, Director, Indian Health Service.

[FR Doc. 04–14646 Filed 6–28–04; 8:45 am]

BILLING CODE 4160–16–M

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1513–DR]

Illinois; Amendment No. 3 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Illinois (FEMA–1513–DR),

dated April 23, 2004, and related determinations.

DATES: *Effective Date:* June 22, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Under Secretary for Emergency Preparedness and Response, Department of Homeland Security, under Executive Order 12148, as amended, Brad Gair, of FEMA is appointed to act as the Federal Coordinating Officer for this declared disaster.

This action terminates my appointment of Lee Champagne as Federal Coordinating Officer for this disaster.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14661 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1520–DR]

Indiana; Amendment No. 3 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Indiana (FEMA–1520-DR), dated June 3, 2004, and related determinations.

DATES: *Effective Date:* June 22, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Indiana is hereby amended to include the following areas among those areas determined to have been adversely affected by the catastrophe declared a major disaster by the President in his declaration of June 3, 2004:

Greene and Owen Counties for Individual Assistance (already designated for Public Assistance.)

Brown, Clay, Delaware, Henry, Jasper, Lake, Madison, Monroe, Newton, Putnam, and Tipton Counties for Individual Assistance.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14665 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1518–DR]

Iowa; Amendment No. 5 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Iowa (FEMA–1518–DR), dated May 25, 2004, and related determinations.

DATES: *Effective Date:* June 22, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Iowa is hereby amended to include the following areas among those areas determined to have been adversely affected by the catastrophe declared a major disaster by the President in his declaration of May 25, 2004:

Clay and Polk Counties for Public Assistance (already designated for Individual Assistance.)

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program-Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14663 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1523–DR]

Kentucky; Amendment No. 1 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the Commonwealth of Kentucky (FEMA–1523–DR), dated June 10, 2004, and related determinations.

EFFECTIVE DATE: June 21, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the Commonwealth of Kentucky is hereby amended to include the following areas among those areas determined to have been adversely affected by the catastrophe declared a major disaster by the President in his declaration of June 10, 2004:

Breathitt, Elliott, Estill, Franklin, Harlan, Henderson, Knott, Laurel, Lawrence, Lee, Letcher, Menifee, Ohio, Pulaski, Rowan, and Wolfe Counties for Public Assistance

(already designated for Individual Assistance).
Boyd, Carter, Fleming, and Jackson Counties for Public Assistance.
Daviess County for Individual Assistance (already designated for Public Assistance).
Bath, Fleming, Hancock, Lewis, Mason, Nicholas, and Robertson Counties for Individual Assistance.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14666 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1523–DR]

Kentucky; Amendment No. 2 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster for the Commonwealth of Kentucky (FEMA–1523–DR), dated June 10, 2004, and related determinations.

DATES: *Effective Date:* June 18, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: Notice is hereby given that the incident period for this disaster is closed effective June 18, 2004.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14667 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1517–DR]

Nebraska; Amendment No. 3 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Nebraska (FEMA–1517–DR), dated May 25, 2004, and related determinations.

DATES: *Effective Date:* June 22, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: The notice of a major disaster declaration for the State of Nebraska is hereby amended to include the following areas among those areas determined to have been adversely affected by the catastrophe declared a major disaster by the President in his declaration of May 25, 2004:

Buffalo and Pawnee Counties for Public Assistance (already designated for Individual Assistance).
Antelope, Greeley, Howard, Nance, Pierce, Red Willow, and Sherman Counties for Public Assistance.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14662 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1519–DR]

Ohio; Amendment No. 2 to Notice of a Major Disaster Declaration

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This notice amends the notice of a major disaster declaration for the State of Ohio (FEMA–1519–DR), dated June 3, 2004, and related determinations.

DATES: *Effective Date:* June 22, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington, DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Under Secretary for Emergency Preparedness and Response, Department of Homeland Security, under Executive Order 12148, as amended, Lee Champagne, of FEMA is appointed to act as the Federal Coordinating Officer for this declared disaster.

This action terminates my appointment of Brad Gair as Federal Coordinating Officer for this disaster.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations: 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance

Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14664 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[FEMA–1526–DR]

Wisconsin; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, Emergency Preparedness and Response Directorate, Department of Homeland Security.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Wisconsin (FEMA–1526-DR), dated June 18, 2004, and related determinations.

DATES: *Effective Date:* June 18, 2004.

FOR FURTHER INFORMATION CONTACT: Magda Ruiz, Recovery Division, Federal Emergency Management Agency, Washington,DC 20472, (202) 646–2705.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated June 18, 2004, the President declared a major disaster under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5206 (the Stafford Act), as follows:

I have determined that the damage in certain areas of the State of Wisconsin, resulting from severe storms and flooding beginning on May 19, 2004, and continuing, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121–5206 (the Stafford Act). I, therefore, declare that such a major disaster exists in the State of Wisconsin.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes, such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Individual Assistance and Public Assistance in the designated areas, and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Public Assistance, Hazard Mitigation, and the Other Needs Assistance under section 408 of the Stafford Act will be limited to 75 percent of the total eligible costs.

Further, you are authorized to make changes to this declaration to the extent allowable under the Stafford Act.

The time period prescribed for the implementation of section 310(a), Priority to Certain Applications for Public Facility and Public Housing Assistance, 42 U.S.C. 5153, shall be for a period not to exceed six months after the date of this declaration.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Under Secretary for Emergency Preparedness and Response, Department of Homeland Security, under Executive Order 12148, as amended, Ron Sherman, of FEMA is appointed to act as the Federal Coordinating Officer for this declared disaster.

I do hereby determine the following areas of the State of Wisconsin to have been affected adversely by this declared major disaster:

Columbia, Dodge, Fond du Lac, Jefferson, Kenosha, Ozaukee, and Winnebago Counties for Individual Assistance.

Clark, Columbia, Crawford, Dodge, Fond du Lac, Grant, Green Lake, Kenosha, Ozaukee, Vernon, and Winnebago Counties for Public Assistance.

All counties within the State of Wisconsin are eligible to apply for assistance under the Hazard Mitigation Grant Program.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund Program; 97.032, Crisis Counseling; 97.033, Disaster Legal Services Program; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance; 97.048, Individual and Household Housing; 97.049, Individual and Household Disaster Housing Operations; 97.050 Individual and Household Program—Other Needs, 97.036, Public Assistance Grants; 97.039, Hazard Mitigation Grant Program.)

Michael D. Brown,

Under Secretary, Emergency Preparedness and Response, Department of Homeland Security.

[FR Doc. 04–14668 Filed 6–28–04; 8:45 am]

BILLING CODE 9110–10–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Notice of Availability of the Sacramento River National Wildlife Refuge Draft Comprehensive Conservation Plan and Environmental Assessment for Review and Comment, and Notice of Public Meetings

AGENCY: Fish and Wildlife Service, Department of the Interior.

ACTION: Notice of availability and notice of public meetings.

SUMMARY: The U.S. Fish and Wildlife Service (Service) announces that the Sacramento River National Wildlife Refuge (Refuge) Draft Comprehensive Conservation Plan and Environmental Assessment (Draft CCP/EA) is available for review and comment. The Draft CCP/EA was prepared pursuant to the National Wildlife Refuge System Administration Act of 1966, as amended by the National Wildlife Refuge System Improvement Act of 1997 (16 U.S.C. dd *et seq.*) (Improvement Act), and the National Environmental Policy Act of 1969, as amended, and describes how the Service proposes to manage this Refuge over the next 15 years. Refuge management changes proposed in the draft CCP include: Restoration of additional acres of historic riparian habitat; increasing public use opportunities including wildlife observation, photography, interpretation, and environmental education; opening additional areas of the Refuge to fishing; and opening the Refuge to waterfowl, deer, and upland gamebird hunting. Also available for review with the Draft CCP/EA, are the draft compatibility determinations for hunting; fishing; environmental education; wildlife observation, photography, and interpretation; research; camping and boating; farming; and grazing.

DATES: Please provide written comments to the address below by August 20, 2004. Public meetings will be held on:

1. July 20, 2004, 6 p.m. to 8 p.m., Willows, CA.
2. July 21, 2004, 6 p.m. to 8 p.m., Chico, CA.
3. July 27, 2004, 6 p.m. to 8 p.m., Red Bluff, CA.
4. July 29, 2004, 6 p.m. to 8 p.m., Colusa, CA.

ADDRESSES: Comments on the Draft CCP/EA should be addressed to Jackie Ferrier, Refuge Planner, Sacramento National Wildlife Refuge Complex, 752 County Road 99 W, Willows, California, 95988. Comments may also be submitted at the public meetings or via electronic mail to *Sacramentovalleyrefuges@fws.gov.*

The public meeting locations are:

1. Willows Memorial Hall, 525 W. Sycamore Street, Willows, CA.

2. Masonic Family Center, 1110 W. East Avenue, Chico, CA.

3. Community Center—Rose Room, 1500 S. Jackson Street, Red Bluff, CA

4. Colusa Industrial Properties—Conference Room, 50 Sunrise Boulevard, Colusa, CA.

FOR FURTHER INFORMATION CONTACT: Project Leader, Sacramento National Wildlife Refuge Complex, 752 County Road 99 W, Willows, California 95988, (530) 934–2801, or Jackie Ferrier, Refuge Planner, Sacramento National Wildlife Refuge Complex, 752 County Road 99 W, Willows, California 95988, (530) 934–2801.

SUPPLEMENTARY INFORMATION: Copies of the Draft CCP/EA may be obtained by writing to Jackie Ferrier, Refuge Planner, Sacramento National Wildlife Refuge Complex, 752 County Road 99 W, Willows, California 95988. Copies of the Draft CCP/EA may be viewed at this address and are also available for viewing and downloading online at *http://sacramentovalleyrefuges.fws.gov* or *http://pacific.fws.gov/planning.* Printed documents will be available for review at the following libraries: Bayliss Library in Glenn; Butte County Library in Chico; Butte County Library in Oroville; Colusa County Library in Colusa; Colusa County Library in Princeton; Corning Library in Corning; Orland City Library in Orland; Tehama County Library in Los Molinos; Tehama County Library in Red Bluff; and Willows Public Library in Willows.

Background

The Refuge was established in 1989 by the authority provided under the Endangered Species Act of 1973, the Fish and Wildlife Act of 1956, and the Emergency Wetlands Resources Act of 1986, using funds made available through the Land and Water Conservation Fund Act of 1965. Sacramento River Refuge is part of the Sacramento National Wildlife Refuge Complex located in the Sacramento Valley of north-central California. The Refuge is located along both banks of the Sacramento River between Red Bluff and Princeton, California, in Glenn, Butte, and Tehama Counties. The Refuge is managed to maintain, enhance and restore habitats for threatened and endangered species, migratory birds, anadromous fish and native fish, wildlife, and plants.

Proposed Action

The Proposed Action is to adopt and implement a Comprehensive Conservation Plan for the Sacramento River Refuge that best achieves the Refuge's purposes; contributes to the National Wildlife Refuge System mission; addresses significant issues and relevant mandates; and is consistent with sound fish and wildlife management. A CCP is required by the Improvement Act of 1997. The purpose in developing CCPs is to provide refuge managers with a 15-year strategy for achieving refuge purposes and contributing to the mission of the National Wildlife Refuge System. The CCP must be consistent with sound principles of fish and wildlife science and conservation; and legal mandates and Service policies. In addition to outlining refuge management direction for conserving wildlife and their habitats, CCPs identify wildlife-dependent recreational opportunities available to the public such as hunting, fishing, wildlife observation and photography, and environmental education and interpretation.

Alternatives

The Draft CCP/EA identifies and evaluates three alternatives for managing Sacramento River National Wildlife Refuge for the next 15 years. Each alternative describes a combination of habitat and public use management prescriptions designed to achieve Refuge purposes. Of the alternatives described below, the Service believes that Alternative B would best achieve these elements, and is, therefore, identified as the Preferred Alternative.

Alternative A, the no action alternative, assumes no change from current management programs and is considered the baseline to compare other alternatives. Under this alternative, the focus of the Refuge would be to continue to restore and maintain riparian habitat for threatened and endangered species, migratory birds, anadromous and native fish, wildlife, and plants. The Refuge would remain closed to visitor services other than the limited existing opportunity for fishing at Packer Lake. Hunting, camping, wildlife observation and photography would not be allowed and access to the Refuge would be limited. Riparian restoration activities would continue on the eight units (La Barranca, Ohm, Pine Creek, Capay, Phelan Island, Dead Man's Reach, Hartley Island, Drumheller Slough) covered under the Environmental Assessment for Proposed Activities on Sacramento River National Wildlife Refuge (2002). Current funding and staffing levels would remain the same.

Alternative B, the preferred alternative would use active and passive management practices to achieve and maintain full restoration and enhancement of all units on the Refuge (5,855 acres), where appropriate. The agricultural program would be phased out as funding for restoration is obtained and restoration takes place. Public use activities would be optimized to allow for a balance of wildlife-dependant public uses (fishing, hunting, environmental education, interpretation, wildlife observation and photography) throughout the entire Refuge. Eighty-four percent of the Refuge would be open for environmental education, interpretation, wildlife observation and photography. Hunting would be allowed on 55 percent of the Refuge. Twenty-three river miles of seasonally submerged areas would be opened to fishing. Camping would be allowed below the ordinary high water mark on gravel bars. Trails and access to the Refuge would also be improved. Staffing and funding levels would need to increase to implement this alternative.

Alternative C would accelerate habitat restoration and maximize public use. The Refuge would use active and passive management practices to achieve and maintain full restoration and enhancement of all units on the Refuge (5,855 acres), where appropriate, as funding becomes available. The agricultural program would end as funding is obtained, and full restoration efforts take place. Public use activities would allow wildlife-dependant public uses throughout the majority of the Refuge (84 percent). Hunting would be allowed on 73 percent of the Refuge. Twenty-three river miles of seasonally submerged areas would be opened to fishing, and camping would be allowed below the ordinary high water mark on gravel bars. Trails and access to the Refuge would also be improved. Funding and staffing levels would have to increase substantially to implement this alternative.

Features Common to All Alternatives

All three alternatives include a number of features in common. Under each alternative, riparian vegetation on La Barranca, Ohm, Pine Creek, Capay, Phelan Island, Dead Man's Reach, Hartley Island and Drumheller Slough units would be restored and enhanced. These restoration activities are addressed in the Environmental Assessment for Proposed Restoration Activities on the Sacramento River

National Wildlife Refuge (2002). Other continuing activities include baseline surveys and monitoring, fire management, law enforcement, and fishing at Packer Lake.

Dated: June 22, 2004.

D. Kenneth McDermond,

Manager, California/Nevada Operations Office, Fish and Wildlife Service.

[FR Doc. 04–14670 Filed 6–28–04; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

Endangered Species Recovery Permit Applications

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of receipt of permit applications.

SUMMARY: The following applicants have applied for a scientific research permit to conduct certain activities with endangered species pursuant to section 10(a)(1)(A) of the Endangered Species Act (16 U.S.C. 1531 *et seq.*). The U.S. Fish and Wildlife Service ("we") solicits review and comment from local, State, and Federal agencies, and the public on the following permit requests.

DATES: Comments on these permit applications must be received on or before July 29, 2004.

ADDRESSES: Written data or comments should be submitted to the U.S. Fish and Wildlife Service, Chief, Endangered Species, Ecological Services, 911 NE. 11th Avenue, Portland, Oregon 97232–4181 (fax: 503–231–6243). Please refer to the respective permit number for each application when submitting comments. All comments received, including names and addresses, will become part of the official administrative record and may be made available to the public.

FOR FURTHER INFORMATION CONTACT: Documents and other information submitted with these applications are available for review, subject to the requirements of the Privacy Act and Freedom of Information Act, by any party who submits a written request for a copy of such documents within 30 days of the date of publication of this notice to the address above (telephone: 503–231–2063). Please refer to the respective permit number for each application when requesting copies of documents.

SUPPLEMENTARY INFORMATION:

Permit No.: TE–086593

Applicant: Arizona Cooperative Fish and Wildlife Research Unit, Tucson, Arizona. The applicant requests a permit to take (capture and collect) the Mohave tui chub (*Gila bicolor mohavensis*) in conjunction with parasite research in San Bernardino County, California, for the purpose of enhancing its survival.

Permit No.: TE–086996

Applicant: David Hacker, Morro Bay, California. The applicant requests a permit to take (harass by survey) the Conservancy fairy shrimp (*Branchinecta conservatio*), the longhorn fairy shrimp (*Branchinecta longiantenna*), the Riverside fairy shrimp (*Streptocephalus wootoni*), the San Diego fairy shrimp (*Branchinecta sandiegonensis*), and the vernal pool tadpole shrimp (*Lepidurus packardi*) in conjunction with surveys throughout the range of each species in California for the purpose of enhancing their survival.

Permit No.: TE–082546

Applicant: Elkhorn Sough Reserve, Watsonville, California. The applicant requests a permit to take (capture and release) the Santa Cruz long-toed salamander (*Ambystoma macrodactyium*) in conjunction with California red-legged frog (*Rana aurora draytonii*) research in San Mateo, Santa Cruz, Monterey, San Luis Obispo, and Santa Barbara Counties, California, for the purpose of enhancing its survival.

Permit No.: TE–802094

Applicant: Carl Page, Cotati, California. The permittee requests an amendment to take (harass by survey, capture, handle, and release) the unarmored threespine stickleback (*Gasterosteus aculeatus williamsoni*) in conjunction with inventories throughout the range of the species in California for the purpose of enhancing its survival.

Permit No.: TE–806679

Applicant: Spring Rivers Ecological Sciences, Cassel, California. The permittee requests an amendment to take (collect tissue) the Shasta crayfish (*Pacifastacus fortis*) in conjunction with genetic research throughout the species range in California for the purpose of enhancing its survival.

We solicit public review and comment on each of these recovery permit applications.

Dated: May 25, 2004.

Paul Henson,

Manager, California/Nevada Operations Office, Region 1, Fish and Wildlife Service.

[FR Doc. 04–14671 Filed 6–28–04; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[CA–339–04–1030–DR]

Notice of Availability of Record of Decision for the Headwaters Forest Reserve Resource Management Plan (RMP)/Environmental Impact Statement (EIS)

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of availability of Record of Decision (ROD).

SUMMARY: In accordance with the National Environmental Policy Act (NEPA), the Federal Land Policy and Management Act (FLPMA), the Bureau of Land Management (BLM) management policies and Public Law 105–83 (Headwaters authorizing legislation), the BLM announces the availability of the RMP/ROD for the Headwaters Forest Reserve located in Humboldt County, Arcata, California. The California State Director will sign the RMP/ROD, which becomes effective immediately.

ADDRESSES: Copies of the Headwaters Forest Reserve RMP/ROD are available upon request from the Field Manager, Arcata Field Office, Bureau of Land Management, at 1695 Heindon Road Arcata, California 95521–4573 or via the Internet at *www.ca.blm.gov/arcata*.

FOR FURTHER INFORMATION CONTACT: Dan Averill, at 1695 Heindon Road, Arcata, California 95521–4573, or phone number: 707–825–2300, or *Daniel_Averill@ca.blm.gov*.

SUPPLEMENTARY INFORMATION: The Headwaters Forest Reserve RMP/ROD was developed with broad public participation through a three (3)-year collaborative planning process. This RMP/ROD addresses management on approximately 7500 acres of public land in the planning area, which was acquired through Congressional designation in 1999 by the BLM and the State of California with the U.S. Department of Interior (DOI) acquiring fee title and the State of California acquiring a conservation easement over the property. These public lands, known as the Headwaters Forest Reserve, are managed to protect old-growth redwoods and the headwaters of two major stream systems. The Reserve provides critical habitat for several terrestrial and aquatic wildlife species including five species federally listed as threatened: Coho salmon, chinook salmon, steelhead trout, marbled murrelet (a threatened seabird) and the northern spotted owl.

The RMP presents management goals and direction for long-term management of the Reserve. The plan addresses future management actions at the land-use plan, program, and site level and analyzes the extent and magnitude of several types of actions, such as watershed restoration, forest restoration, and development of limited recreation facilities, including a trail system allowing public access.

The approved Headwaters Forest Reserve RMP consists of essentially the same array of selected alternatives that was identified in the Proposed Headwaters Forest Reserve RMP/Final Environmental Impact Statement (PRMP/FEIS), published in September 2003. BLM received 79 protests to the PRMP/FEIS. No inconsistencies with State or local plans, policies, or programs were identified during the Governor's consistency review of the PRMP/FEIS and no editorial modifications were made in preparing the RMP/ROD.

Mike Pool,

California State Director.

[FR Doc. 04–14724 Filed 6–28–04; 8:45 am]

BILLING CODE 4310–40–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Environmental Documents Prepared for Proposed Oil and Gas Operations on the Gulf of Mexico Outer Continental Shelf (OCS)

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Notice of the availability of environmental documents prepared for OCS mineral proposals on the Gulf of Mexico (GOM) OCS.

SUMMARY: MMS in accordance with Federal Regulations that implement the National Environmental Policy Act (NEPA) announces the availability of NEPA-related Site-Specific Environmental Assessments (SEA) and Findings of No Significant Impact (FONSI), prepared by MMS for the following oil and gas activities proposed on the Gulf of Mexico OCS.

FOR FURTHER INFORMATION CONTACT: Public Information Unit, Information Services Section at the number below. Minerals Management Service, Gulf of Mexico OCS Region, Attention: Public Information Office (MS 5034), 1201 Elmwood Park Boulevard, Room 114, New Orleans, Louisiana 70123–2394, or by calling 1–800–200–GULF.

SUPPLEMENTARY INFORMATION: MMS prepares SEAs and FONSIs for proposals that relate to exploration for and the development/production of oil and gas resources on the GOM OCS. These SEAs examine the potential environmental effects of activities described in the proposals and present MMS conclusions regarding the significance of those effects. Environmental Assessments are used as a basis for determining whether or not approval of the proposals constitutes major Federal actions that significantly affect the quality of the human environment in the sense of NEPA Section 102(2)(C). A FONSI is prepared in those instances where MMS finds that approval will not result in significant effects on the quality of the human environment. The FONSI briefly presents the basis for that finding and includes a summary or copy of the SEA.

This notice constitutes the public notice of availability of environmental documents required under the NEPA Regulations.

This listing includes all proposals for which the GOM OCS Region prepared a FONSI in the period subsequent to publication of the preceding notice.

Activity/operator	Location	Date
Samedan Oil Corporation, Structure Removal SEA ES/SR 03–210, 03–211, 03–212.	East Cameron, Block 66, Lease OCS–G 04417, located 23 miles from the nearest Louisiana shoreline.	01/06/04
Marathon Oil Corporation, Initial Exploration Plan SEA N–7910	DeSoto Canyon, Block 354, Lease OCS–G 23507, located 80 miles from the nearest Louisiana shoreline.	01/14/04
LLOG Exploration Offshore, Inc., Supplemental Development Operations Coordination Plan SEA S–6308.	High Island, Block A–367, Lease OCS–G 23222, located 124 miles from the nearest Texas shoreline.	01/29/04
C & C Technologies, Inc., Geological & Geophysical Exploration Plan for BHP Billiton (Americas) Inc. SEA L04–01.	Located in the central Gulf of Mexico south of the eastern Louisiana shoreline.	02/05/04
TDI-Brooks International, Geological & Geophysical Exploration Plan for Shell Exploration SEA M04–01.	Located in the eastem Gulf of Mexico east of the Freeport, Texas shoreline.	02/05/04
BP America Production Company, Inc., Structure Removal SEA ES/SR 04–002.	West Cameron, Block 71, Lease OCS–00244, located 10 miles from the nearest Louisiana shoreline.	02/09/04
Bois d'Arc offshore, Ltd, Structure Removal SEA ES/SR 04–003, 04–004.	South Timbalier, Block 50, Lease OCS–G 04119, located 10 miles from the nearest Louisiana shoreline.	02/11/04
El Paso Production Oil & Gas Company, Structure Removal SEA ES/SR 04–005.	Viosca Knoll, Block 24, Lease OCS–G 08763, located 17 miles from the nearest Louisiana shoreline.	02/17/04
Bois d'Arc Offshore, Ltd, Structure Removal SEA ES/SR 03–198.	South Timbalier, Block 34, Lease OCS–G 04842, located 5 miles from the nearest Louisiana shoreline.	02/19/04
Bois d'Arc Offshore, Ltd, Structure Removal SEA ES/SR 04–006, 04–007.	South Timbalier, Block 34, Lease OCS–G 04842, located 5 miles from the nearest Louisiana shoreline.	02/19/04
Walter Oil & Gas Corporation, Structure Removal SEA ES/SR 04–009.	East Cameron (South Addition), Block 111, Lease OCS–G 12845, located 81 miles from the nearest Vermilion Parish, Louisiana shoreline.	02/25/04
Coastal Planning & Engineering, Inc., Geological & Geophysical Exploration Plan for Galveston & Jefferson Counties, TX SEA T04–04.	Located in the western Gulf of Mexico east of Galveston & Jefferson Counties, Texas.	02/26/04
Chevron, U.S.A., Inc., Lease-Term Pipeline SEA P–14470	Grand Isle, Block 37, Lease OCS–G 00392, closest distance is located 3 miles from the nearest Louisiana shoreline.	03/01/04
C & C Technologies, Inc., Geological & Geophysical Exploration Plan for Kerr McGee Oil & Gas Company SEA L04–04.	Located in the central Gulf of Mexico south of the nearest eastern Louisiana shoreline.	03/03/04

Activity/operator	Location	Date
Union Oil Company of California, Structure Removal SEA ES/SR 04–021.	East Cameron, Block 62, Lease OCS–G 13574, located 19 miles from the nearest Louisiana shoreline.	03/04/04
Devon Energy Corporation, Structure Removal SEA ES/SR 04–012.	Galveston, Block 362, Lease OCS–G 14841, located 18 miles from the nearest Texas shoreline.	03/04/04
Devon Energy Corporation, Structure Removal SEA ES/SR 04–015.	West Cameron, Block 165, Lease OCS–G 00758, located 25 miles from the nearest Louisiana shoreline.	03/04/04
Devon Energy Corporation, Structure Removal SEA ES/SR 04–013, 04–014.	West Cameron, Block 20, Lease OCS–G 00680, located 5 miles from the nearest Louisiana shoreline.	03/11/04
Devon Louisiana Corporation, Structure Removal SEA ES/SR 04–010.	Brazos, Block 377, Lease OCS–G 14803, located 13 miles from the nearest Texas shoreline.	03/17/04
Devon Louisiana Corporation, Structure Removal SEA ES/SR 04–011.	Brazos, Block 552, Lease OCS–G 11283, located 18 miles from the nearest Texas shoreline.	03/17/04
Walter Oil & Gas Corporation, Structure Removal SEA ES/SR 04–035.	High Island, Block 200, Lease OCS–G 09086, located 33 miles from the nearest Texas shoreline.	03/17/04
Canyon Offshore, Inc., Geological & Geophysical Exploration Plan for BP Exploration & Production, Inc. SEA L04–05.	Located in the central Gulf of Mexico south of the nearest eastern Louisiana shoreline.	03/17/04
C & C Technologies, Inc., Geological & Geophysical Exploration Plan for Shell International Exploration & Production, Inc. SEA T04–07.	Located in the central Gulf of Mexico south of the eastern Louisiana shoreline.	03/17/04
SPN Resources, L.L.C., Structure Removal SEA ES/SR RA–2004–01.	Mobile, Block 864, Lease OCS–G 05064, located 6 miles from the nearest Alabama shoreline.	03/17/04
Chevron U.S.A., Inc., Structure Removal SEA ES/SR 04–016, 04–017.	Mobile, Block 945, Lease OCS–G 07847; Viosca Knoll, Block 27, Lease OCS–G 06868; located 15 miles from the nearest Mississippi shoreline and located 18 miles from the nearest Louisiana shoreline, respectively.	03/17/04
Energy Resource Technology, Inc., Structure Removal SEA ES/SR 04–031, 04–032, 04–033, 04–034.	South Marsh Island, Ship Shoal, Vermilion, West Cameron; Blocks 15, 220, 171, 202; Leases OCS–G 09534, 12950, 01130, 05182, respectively; located 34 to 40 miles from the nearest Louisiana shoreline.	03/17/04
J. M. Huber Corporation, Structure Removal SEA ES/SR 04–018, 04–019.	South Timbalier, Block 28, Lease OCS–G 01362, located 5 miles from the nearest Louisiana shoreline.	03/17/04
Samedan Oil Corporation, Structure Removal SEA ES/SR 04–022, 04–023, 04–024, 04–025.	West Cameron (South Addition), Blocks 445, 463, Leases OCS–G 09423, 04093; High Island (East Addition), Blocks A232, A244, Leases OCS–G 21353, 05010, located 70 to 75 miles south of the nearest Texas shoreline and 80 miles south of the nearest Louisiana shoreline.	03/17/04
Samedan Oil Corporation, Structure Removal SEA ES/SR 04–036.	Vermilion (South), Block 336, Lease OCS–G 13892, located 90 miles from the nearest Louisiana shoreline.	03/23/04
Anadarko Petroleum Corporation, Structure Removal SEA ES/SR 04–037.	South Marsh, Block 241, Lease OCS–310, located 15 miles from the nearest Louisiana shoreline.	03/24/04
Devon Energy Corporation, Structure Removal SEA ES/SR 04–038.	West Cameron (South Addition), Block 533, Lease OCS–G 02225, located 90 miles southwest from the nearest Louisiana shoreline.	03/24/04
Newfield Exploration Company, Structure Removal SEA ES/SR 04–042.	West Cameron (South), Block 535, Lease OCS–G 15109, located 97 miles from the nearest Louisiana shoreline.	03/29/04
Union Oil Company of California, Structure Removal SEA ES/SR 04–041.	West Cameron (West), Block 297, Lease OCS–G 15077, located 27 miles from the nearest Louisiana shoreline.	03/29/04
BP America Production Company, Structure Removal SEA ES/SR 04–043.	West Cameron, Block 36, Lease OCS–G 11753, located 7 miles from the nearest Louisiana shoreline.	03/30/04
Devon Louisiana Corporation, Structure Removal SEA ES/SR 04–029, 04–030.	Eugene Island, Block 129, Lease OCS–G 00054, located 29 miles from the nearest Louisiana shoreline.	03/31/04
Devon Louisiana Corporation, Structure Removal SEA ES/SR 04–026.	Galveston, Block 393, Lease OCS–G 03741, located 23 miles from the nearest Texas shoreline.	03/31/04
Devon Louisiana Corporation, Structure Removal SEA ES/SR 04–027.	Galveston, Block 420, Lease OCS–G 14146, located 22 miles from the nearest Texas shoreline.	03/31/04
Devon Louisiana Corporation, Structure Removal SEA ES/SR 04–028.	High Island, Block 140, Lease OCS–G 00518, located 17 miles from the nearest Texas shoreline.	03/31/04

Persons interested in reviewing environmental documents for the proposals listed above, or obtaining information about SEAs and FONSIs prepared for activities on the GOM OCS are encouraged to contact MMS.

Dated: May 27, 2004.

Chris C. Oynes,

Regional Director, Gulf of Mexico OCS Region.

[FR Doc. 04–14722 Filed 6–28–04; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

Agency Information Collection Activities: Proposed Collection; Comments Requested

ACTION: 60-Day notice of information collection under review: Federal Firearms License (FFL) renewal application.

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF), has submitted the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for "sixty days" until August 30, 2004. This process is conducted in accordance with 5 CFR 1320.10.

If you have comments especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact David Adinolfi, Firearms and Explosives National Licensing Center, 2600 Century Parkway, Atlanta, Georgia 30044.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
—Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
—Enhance the quality, utility, and clarity of the information to be collected; and
—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

Overview of this information collection:

(1) *Type of Information Collection:* Extension of a currently approved collection.

(2) *Title of the Form/Collection:* Federal Firearms License (FFL) RENEWAL Application.

(3) Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number: ATF F 8 (5310.11). Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) Affected public who will be asked or required to respond, as well as a brief abstract: Primary: Business or other for-profit. Other: Individual or households. The form is filed by the licensee desiring to renew a Federal firearms license. It is used to identify the applicant, locate the business/collection premises, identify the type of business/collection activity, and determine the eligibility of the applicant.

(5) An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond: It is estimated that 35,000 respondents will complete a 25 minute form.

(6) An estimate of the total public burden (in hours) associated with the collection: There are an estimated 14,700 annual total burden hours associated with this collection.

If additional information is required contact: Brenda E. Dyer, Deputy Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Patrick Henry Building, Suite 1600, 601 D Street, NW., Washington, DC 20530.

Dated: June 23, 2004.

Brenda E. Dyer,

Deputy Clearance Officer, Department of Justice.

[FR Doc. 04–14656 Filed 6–28–04; 8:45 am]

BILLING CODE 4410–FY–P

DEPARTMENT OF JUSTICE

Bureau of Alcohol, Tobacco, Firearms and Explosives

Agency Information Collection Activities: Proposed Collection; Comments Requested

ACTION: 60-Day notice of information collection under review: User—Limited Permit (Explosives).

The Department of Justice (DOJ), Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF), has submitted the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection is published to obtain comments from the public and affected agencies. Comments are encouraged and will be accepted for "sixty days" until August 30, 2004. This process is conducted in accordance with 5 CFR 1320.10.

If you have comments especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact Lilia Vannett, Chief, Firearms and Explosives National Licensing Center, Room 400, 2600 Century Parkway, Atlanta, Georgia 30044.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

—Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
—Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
—Enhance the quality, utility, and clarity of the information to be collected; and
—Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

Overview of this information collection:

(1) *Type of Information Collection:* Revision of a currently approved collection.

(2) *Title of the Form/Collection:* User—Limited Permit (Explosives).

(3) Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: Form Number: ATF F 5400.6. Bureau of Alcohol, Tobacco, Firearms and Explosives.

(4) Affected public who will be asked or required to respond, as well as a brief abstract: Primary: Business or other for-profit. Other: Individuals or households. The User-Limited Permit is useful to the person making a one-time purchase of explosives from out-of-state. This permit is not transferable and valid only for a single transaction involving the type and quantity of explosive materials specified on the permit. It is nonrenewable. The explosives distributor makes entries on the form and returns the form to the permittee to prevent reuse of the permit.

(5) An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond: It is estimated that 1,092 respondents will complete and retain the form in 12 minutes.

(6) An estimate of the total public burden (in hours) associated with the collection: There are an estimated 218 annual total burden hours associated with this collection.

If additional information is required contact: Brenda E. Dyer, Deputy Clearance Officer, Policy and Planning Staff, Justice Management Division, Department of Justice, Patrick Henry Building, Suite 1600, 601 D Street NW., Washington, DC 20530.

Dated: June 23, 2004.

Brenda E. Dyer,

Deputy Clearance Officer, Department of Justice.

[FR Doc. 04–14657 Filed 6–28–04; 8:45 am]

BILLING CODE 4410–FY–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[Docket No. DEA–245N]

Importing Controlled Substances From Canada and Other Foreign Countries

AGENCY: Drug Enforcement Administration (DEA), Justice.

ACTION: Notice.

SUMMARY: On April 27, 2001, the Drug Enforcement Administration (DEA) published a notice in the **Federal Register** (66 FR 21181) to provide guidance to prescribers, pharmacists, law enforcement authorities, regulatory authorities, and the public concerning the application of current laws and regulations as they relate to the use of the Internet for dispensing, purchasing, or importing controlled substances. Since publication of that notice, DEA has noted increasing numbers of both Internet Web sites and "brick and mortar businesses" claiming to be able to assist individual consumers in purchasing prescription medications, including controlled substances, from Canada and other foreign countries. This document reiterates current Federal law and DEA regulations pertaining to the importation of controlled substances from foreign countries. Persons who have controlled substances sent from other countries into the United States violate Federal law unless those persons are registered with DEA as importers of controlled substances and have received from DEA an import permit.

FOR FURTHER INFORMATION CONTACT: Patricia M. Good, Chief, Liaison and Policy Section, Office of Diversion Control, Drug Enforcement Administration, Washington, DC 20537, Telephone (202) 307–7297.

SUPPLEMENTARY INFORMATION:

Introduction

Recently, the Drug Enforcement Administration (DEA) has noted increasing public interest in, and use of, both Internet Web sites and "brick and mortar businesses" claiming to be able to assist individual citizens in having their prescriptions filled at pharmacies in foreign countries and mailed to them in the United States. For purposes of this document, DEA uses the term "brick and mortar businesses" to refer to physical storefront locations of a business having direct contact with customers. It has been DEA's experience that the vast majority of such prescriptions are for drugs for treatment of such conditions as high blood pressure or cholesterol, arthritis pain, diabetes, infections, etc., which are not controlled substances; of all prescriptions issued each year, approximately 89% are for non-controlled substances and 11% are for controlled substances. DEA is concerned solely with the 11% of controlled substances prescriptions. (Controlled substances are those prescription medications which, among other factors, have the potential for abuse, which may lead to physical or psychological dependency.) The remaining 89% of prescriptions that do not involve controlled substances are not the subject of this notice or any requirement under the Controlled Substances Act or the Controlled Substances Import and Export Act.

Background

DEA administers the Controlled Substances Act and the Controlled Substances Import and Export Act (herein jointly called the CSA) which together form the basis for laws governing the manufacture, distribution, dispensing, importation and exportation of controlled substances. These laws may be found in Title 21, United States Code (U.S.C.), Sections 801–971. Regulations implementing these laws are found in Title 21, Code of Federal Regulations (CFR), Parts 1300 to 1316. Together, the CSA and its implementing regulations provide the framework for DEA to ensure adequate supplies of controlled substances for the legitimate medical, scientific, research, and industrial needs of the United States, while preventing the diversion of those controlled substances.

To do this, the CSA creates a "closed system of drug distribution" which requires DEA to register manufacturers, distributors, dispensers, importers, and exporters of controlled substances within the legitimate distribution chain, and makes transactions outside the legitimate distribution chain illegal.

The CSA provides that any person who causes controlled substances to be brought into the United States by any means—including causing items to be sent from other countries to the United States by mail or private shipping company—has imported controlled substances into the United States and is subject to criminal penalties (21 U.S.C. 951, 952, 960). Except as authorized by law, no person may import a controlled substance into the United States unless such person is registered with DEA and has obtained the appropriate permit or authorization from DEA to engage in such importation (21 U.S.C. 957). Illegal importation of controlled substances into the United States is a felony that may result in imprisonment and fines (21 U.S.C. 960).

On April 27, 2001, DEA published a notice in the **Federal Register** (66 FR 21181) to provide guidance to prescribers, pharmacists, law enforcement authorities, regulatory authorities, and the public concerning the application of current laws and regulations as they relate to the use of the Internet for dispensing, purchasing, or importing controlled substances. Since publication of that notice, DEA has noted increasing numbers of both Internet web sites and "brick and mortar" businesses claiming to be able to assist individual consumers in purchasing prescription medications, including controlled substances, from Canada and other foreign countries. This document reiterates current Federal law and DEA regulations pertaining to the importation of controlled substances from foreign countries.

Explanation Regarding Controlled Substances

Medications which can be purchased without a prescription are over the counter medications. Drugs which may only be obtained pursuant to a practitioner's order are prescription medications. Many drugs and medications which have potential for abuse are controlled substances. Most drugs requiring a prescription from a physician or other practitioner are not controlled substances. The CSA and its implementing regulations assign controlled substances to one of five "schedules." These substances are placed in a schedule based on, among other factors, their potential for abuse, which may lead to physical or psychological dependency. Schedule I substances have no accepted medical use for treatment in the United States and are not available by prescription. Schedule II controlled substances have a high potential for abuse and a currently accepted medical use in treatment in the United States or a currently accepted medical use with severe restrictions. The substances in each successive schedule have a lower potential for abuse and dependency relative to the higher schedules.

Schedule II, III, IV and V controlled substances may be dispensed by, or pursuant to, the lawful order of a practitioner acting in the usual course of professional practice for a legitimate medical purpose. Practitioners include, but are not limited to, doctors, dentists, veterinarians, and, where authorized by an appropriate state authority, physician assistants and advance practice nurses. Controlled substances include narcotics (pain relievers), stimulants, depressants, hallucinogens, and anabolic steroids. A listing of controlled substances can be found in 21 CFR Part 1308. Examples of controlled substances may also be found at the Diversion Control Program Web site: http://www.deadiversion.usdoj.gov. A few examples are shown below.

Schedule	Example of Controlled Substances
Schedule I	Heroin, marijuana, methylenedioxymethamphetamine (MDMA; Ecstasy).
Schedule II	Amphetamine, codeine, fentanyl (Duragesic®), hydromorphone (Dilaudid®), meperidine (Demerol®), methadone (Dolophine®), methylphenidate (Ritalin®, Metadate ER®, Concerta®), morphine, oxycodone (Percodan®, Tylox®, OxyContin®).
Schedule III	Anabolic steroids (Anadrol®, Depo-Testosterone®, Dianabol®), phendimetrazine (Prelu-2®), acetaminophen with codeine, hydrocodone/acetaminophen (Lorcet®, Vicodin®).
Schedule IV	Alprazolam (Xanax®), diazepam (Valium®), lorazepam (Ativan®), phentermine (Fastin®, Ionamin®, Adipex-P®).
Schedule V	Some cough preparations that contain a limited amount of codeine.

Basic Requirements for Prescribing and Dispensing Controlled Substances

Only practitioners who are authorized to prescribe controlled substances by the state in which they are licensed, are registered with DEA, and are acting in the usual course of their professional practice for a legitimate medical purpose may prescribe controlled substances. Pharmacies filling prescriptions for controlled substances must be licensed to dispense controlled substances by the state(s) in which they operate and also be registered with DEA. A prescription not issued for a legitimate medical purpose and not in the usual course of professional practice (or not for legitimate and authorized research) is not valid.

Importing Controlled Substances into the United States

Federal law and DEA regulations prohibit any person or entity from importing any controlled substance into the United States unless that person or entity is registered with DEA and specifically authorized by DEA to import the controlled substances (21 U.S.C. 952 and 957). Controlled substances may only be imported into the United States for medical and scientific purposes or other legitimate purposes (21 U.S.C. 952). Controlled substances may only be imported pursuant to a permit or declaration, as applicable, obtained from DEA (21 U.S.C. 952, 21 CFR 1312.11). As with all other registered handlers of controlled substances, importers of controlled substances must provide effective controls and procedures to guard against the theft and diversion of controlled substances (21 CFR 1301.71). Such security includes, depending on the schedule of the controlled substance, a vault, safe, cage or other secure storage facility (21 CFR 1301.72). The regulations specify the construction of each storage facility to adequately secure these controlled substances. Such storage facility, regardless of its type, must be alarmed, and the alarm system, upon attempted unauthorized entry, must transmit a signal directly to a central protection company or a local or state police agency which has a legal duty to respond, or a 24-hour control station operated by the importer (21 CFR 1301.72). As with other registered handlers of controlled substances, importers must design and operate a system to disclose suspicious orders (21 CFR 1301.74(b)), and must file reports regarding the theft or significant loss of controlled substances with DEA (21 CFR 1301.74(c)). As with other registered handlers of controlled substances, importers must maintain records regarding controlled substances imported, received, sold, delivered or destroyed (21 CFR 1304.21, 1304.22(d)). Finally, importers must take a periodic inventory, at least biennially, of all controlled substances on hand (21 CFR 1304.03, 1304.11(e)(4)).

Illegal importation of controlled substances is a felony that may result in imprisonment and fines (21 U.S.C. 960).

Purchasing Controlled Substances From Foreign Countries

DEA has become aware of both "brick and mortar businesses" and Internet sites within the United States which claim that they are able to have United States consumers' prescriptions filled in Canada or other foreign countries, or are able to facilitate a United States consumer's acquisition of prescription medications from pharmacies in Canada or other foreign countries. These stores and Internet sites accomplish this in a number of ways. Some stores or Internet sites send prescriptions issued by United States practitioners to Canadian companies which then have Canadian practitioners write equivalent prescriptions for Canadian medications. Some companies simply mail the United States prescriptions to Canadian pharmacies which fill the prescriptions based on the United States prescriptions only.

Some Internet sites do not require a prescription, but instead require the consumer to complete a questionnaire to receive a desired medication. These sites claim the questionnaire is evaluated by a physician and a prescription is written, if appropriate, based on the information provided in the questionnaire. Some foreign Internet sites claim they can legally sell controlled substances to consumers within the United States. Many of these sites require United States patients to waive their right to take legal action if a medication error occurs. Still other Internet sites sell listings of foreign Internet pharmacies which these sites claim will sell prescription medications without prescriptions.

It is illegal for a United States consumer or business to have controlled substances shipped to the United States from a foreign country unless the person receiving the controlled substances is registered with DEA as an importer or researcher and is in compliance with 21 U.S.C. 952 and 957 and 21 CFR Part 1312. Importers must comply with recordkeeping and reporting requirements regarding the controlled substances they import.

The acquisition of a controlled substance from a foreign country by any person other than a DEA-registered importer or researcher is a violation of the Controlled Substances Act. Therefore, United States pharmacies which fill prescriptions for controlled substances by obtaining those controlled substances from Canada, or any other foreign country, are in violation of the Controlled Substances Act, regardless of whether the consumer possesses a legitimate prescription issued by a United States practitioner in the usual course of their professional practice. Likewise, consumers are also in violation of the Controlled Substances Act if they have prescriptions for controlled substances filled in foreign countries and shipped to the United States.

Personal Medical Use Exemption

The CSA contains a "personal medical use" exemption (21 U.S.C. 956; 21 CFR 1301.26) which makes a limited allowance for travelers entering and departing the United States who have a legitimate medical need for controlled substances during their journey. Under this exemption, United States residents who travel to foreign countries and non-United States residents who travel to the United States may carry controlled substances on their person for their legitimate personal medical use. DEA published a Notice of Proposed Rulemaking in the **Federal Register** on September 11, 2003 addressing the personal medical use exemption (68 FR 53529).

The "personal medical use" exemption only applies to individual travelers who themselves are entering or departing the United States who require controlled substances. The "personal medical use" exemption does not apply to the shipment of controlled substances into the United States from a foreign country, regardless of whether the individual receiving the shipment possesses a valid prescription issued by a United States practitioner for the controlled substances, and regardless of the fact that those controlled substances are intended for the personal medical use of an individual. As stated previously, purchasing controlled substances from a foreign country or from a foreign Internet site and having them shipped to a business or individual within the United States is not permitted by the "personal medical use" exemption. Such purchases and shipments are considered "imports" under the Controlled Substances Act even if the substances are for personal use. Unless the business or individual within the United States receiving the shipment is registered as an importer with DEA and is in compliance with the requirements of Federal law and DEA regulations, such shipments are illegal and subject to seizure.

Conclusion

The Controlled Substances Act prohibits persons from importing controlled substances into the United States unless those persons are registered with DEA to do so. Persons importing controlled substances into the United States without being properly registered to do so are in violation of the CSA and are subject to prosecution for violation of Federal drug laws.

Dated: May 24, 2004.

William J. Walker,

Deputy Assistant Administrator, Office of Diversion Control.

[FR Doc. 04–14716 Filed 6–28–04; 8:45 am]

BILLING CODE 4410–09–P

NUCLEAR REGULATORY COMMISSION

Meeting; Sunshine Act

DATE: Weeks of June 28, July 5, 12, 19, 26, August 2, 2004.

PLACE: Commissioners' Conference Room, 11555 Rockville Pike, Rockville, Maryland.

STATUS: Public and closed.

MATTERS TO BE CONSIDERED:

Week of June 28, 2004

There are no meetings scheduled for the week of June 28, 2004.

Week of July 5, 2004—Tentative

Wednesday, July 7, 2004:
1:55 p.m.—Affirmation Session (public meeting) (if needed).

Week of July 12, 2004—Tentative

Tuesday, July 13, 2004:
2:15 p.m.—Discussion of Security Issues (closed—Ex. 1).

Week of July 19, 2004—Tentative

Wednesday, July 21, 2004:
9:30 a.m.—Meeting with Advisory Committee on Nuclear Waste (ACNW) (public meeting) (contact: John Karkins (301) 415–7360). This meeting will be Web cast live at the Web address—*http://www.nrc.gov.*

Week of July 26, 2004—Tentative

There are no meetings scheduled for the week of July 26, 2004.

Week of August 2, 2004—Tentative

There are no meetings scheduled for the week of August 2, 2004.

* The schedule for Commission meetings is subject to change on short notice. To verify the status of meetings call (recording)—(301) 415–1292. Contact person for more information: Dave Gamberoni, (301) 415–1651.

* * * * *

The NRC Commission Meeting Schedule can be found on the Internet at: *http://www.nrc.gov/what-we-do/policy-making/schedule.html.*

* * * * *

The NRC provides reasonable accommodation to individuals with disabilities where appropriate. If you need a reasonable accommodation to participate in these public meetings, or need this meeting notice or the transcript or other information from the public meetings in another format (*e.g.*, braille, large print), please notify the NRC's Disability Program Coordinator, August Spector, at (301) 415–7080, TDD: (301) 415–2100, or by e-mail at *aks@nrc.gov.* Determinations on requests for reasonable accommodation will be made on a case-by-case basis.

* * * * *

This notice is distributed by mail to several hundred subscribers; if you no longer wish to receive it or would like to be added to the distribution please contact the Office of the Secretary, Washington, DC 20555 (301) 415–1969. In addition, distribution of this meeting notice over the Internet system is available. If you are interested in receiving this Commission meeting schedule electronically, please send an electronic message to *dkw@nrc.gov.*

Dated: June 24, 2004.

Dave Gamberoni,

Office of the Secretary.

[FR Doc. 04–14771 Filed 6–25–04; 9:29 am]

BILLING CODE 7590–01–M

OFFICE OF PERSONNEL MANAGEMENT

Proposed Collection; Comment Request for a Revised Information Collection Mail Reinterview Form (OFI 10), OMB No. 3206–0106

AGENCY: Office of Personnel Management.

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (Pub. L. 104–13), this notice announces that the Office of Personnel Management intends to submit to the Office of Management and Budget a request for clearance of a revised information collection. OPM sends the OFI 10 questionnaire to a random sampling of record and personal sources contacted during background investigations when investigators have performed fieldwork. The OFI 10 is used as a quality control instrument designed to ensure the accuracy and integrity of the investigative product, as it inquires of the sources about the investigative procedure employed by the investigator,

the investigator's professionalism, and the information discussed and reported. In addition to the pre-formatted response options, OPM invites the recipients to respond with any other relevant comments or suggestions. A postage-paid envelope is provided with the OFI 10.

Comments are particularly invited on:

- Whether this collection of information is necessary for the proper performance of functions of the Office of Personnel Management and its Center for Federal Investigative Services, which administers its background investigations.
- Whether our estimate of the public burden of this collection is accurate, and based on valid assumptions and methodology; and,
- Ways in which we can minimize the burden of the collection of information on those who are asked to respond, through the use of the appropriate technological collection techniques or other forms of information technology; and,
- Whether the reinterview questionnaire addresses all of the questions relevant to ensure the accuracy and integrity of the investigative product.

It is estimated that 9,600 OFI 10 forms are sent to individual sources annually. Of those, it is estimated that 5,600 individuals will respond. Each form takes approximately six minutes to complete. The estimated annual burden is 560 hours.

For copies of this proposal, contact Mary Beth Smith-Toomey on (202) 606–8358, Fax (202) 418–3251 or e-mail to *mbtoomey@opm.gov*. Please be sure to include a mailing address with your request.

DATES: Comments on this proposal should be received within 60 calendar days from the date of this publication.

ADDRESSES: Send or deliver comments to: Kathy Dillaman, Deputy Associate Director, Center for Federal Investigative Services, U.S. Office of Personnel Management, 1900 E Street, Room 5416, Washington, DC 20415.

FOR INFORMATION REGARDING ADMINISTRATIVE COORDINATION CONTACT: Sabrina Price—Program Analyst, Program Services Group, Center for Federal Investigative Services, U.S. Office of Personnel Management, (202) 606–3534.

Office of Personnel Management.

Kay Coles James,

Director.

[FR Doc. 04–14697 Filed 6–28–04; 8:45 am]

BILLING CODE 6325–38–P

SECURITIES AND EXCHANGE COMMISSION

Issuer Delisting; Notice of Application of Cleco Corporation To Withdraw its Common Stock, $1.00 Par Value, and Associated Rights To Purchase Preferred Stock From Listing and Registration on the Pacific Exchange, Inc. File No. 1–05663

June 23, 2004.

On June 17, 2004, Cleco Corporation, a Louisiana corporation ("Issuer"), filed an application with the Securities and Exchange Commission ("Commission"), pursuant to section 12(d) of the Securities Exchange Act of 1934 ("Act")[1] and Rule 12d2–2(d) thereunder,[2] to withdraw its common stock, $1.00 par value, and associated rights to purchase preferred stock ("Securities"), from listing and registration on the Pacific Exchange, Inc. ("PCX" or "Exchange").

The Board of Directors of the Issuer adopted resolutions on April 23, 2004, to withdraw the Issuer's Securities from listing on the PCX. The Issuer states that the following reasons factored into its decision to withdraw its Securities from the PCX: (i) The Issuer has maintained a dual listing of its Securities on the New York Stock Exchange, Inc. ("NYSE") and the PCX since 1988; (ii) at the time of the 1988 PCX listing, a regional exchange listing was thought to provide added liquidity to a NYSE-traded stock since some investors traded only on regional exchanges. Since that time, the advances in electronic trading platforms have essentially created a single domestic trading platform and eliminated the benefit of dual listings on regional exchanges; (iii) the PCX listing adds additional fees and results in dual reporting requirements and; (iv) the Issuer believes that since the listing on the PCX no longer provides additional value, delisting the Securities will lower fees and reduce reporting activities. In addition, the Issuer states that the Securities will continue to trade on the NYSE.

The Issuer stated in its application that it has complied with PCX's Rule 5.4(b) by complying with all applicable laws in effect in the State of Louisiana and by providing PCX with the required documents governing the removal of securities from listing and registration on the Exchange. The Issuer's application relates solely to the withdrawal of the Securities from listing on the PCX and shall not affect its continued listing on the NYSE or its obligation to be registered under section 12(b) of the Act.[3]

Any interested person may, on or before July 19, 2004, comment on the facts bearing upon whether the application has been made in accordance with the rules of the PCX, and what terms, if any, should be imposed by the Commission for the protection of investors. All comment letters may be submitted by either of the following methods:

Electronic Comments

- Send an e-mail to *rule-comments@sec.gov*. Please include the File Number 1–05663 or;

Paper Comments

- Send paper comments in triplicate to Jonathan G. Katz, Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609.

All submissions should refer to File Number 1–05663. This file number should be included on the subject line if e-mail is used. To help us process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/delist.shtml*). Comments are also available for public inspection and copying in the Commission's Public Reference Room, 450 Fifth Street, NW., Washington, DC 20549. All comments received will be posted without change; we do not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly.

The Commission, based on the information submitted to it, will issue an order granting the application after the date mentioned above, unless the Commission determines to order a hearing on the matter.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[4]

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–14674 Filed 6–28–04; 8:45 am]

BILLING CODE 8010–01–P

[1] 15 U.S.C. 78*l*(d).

[2] 17 CFR 240.12d2–2(d).

[3] 15 U.S.C. 78*l*(b).

[4] 17 CFR 200.30–3(a)(1).

SECURITIES AND EXCHANGE COMMISSION

[Investment Company Act Release No. 26472; 812–13039]

MMA Praxis Mutual Funds, et al.; Notice of Application

June 23, 2004.

AGENCY: Securities and Exchange Commission ("Commission").

ACTION: Notice of an application under section 17(b) of the Investment Company Act of 1940 (the "Act") for an exemption from section 17(a) of the Act.

SUMMARY OF APPLICATION: Applicants request an order to permit certain entities excluded from the definition of investment company under section 3(c)(10) or 3(c)(11) of the Act to transfer certain classes of assets held in separate accounts to two series of a registered open-end management investment company in exchange for shares of the series.

APPLICANTS: MMA Praxis Mutual Funds ("Trust"), The Mennonite Insurance Services Inc. d/b/a MMA Capital Management ("MMA").

FILING DATES: The application was filed on November 14, 2003 and amended on June 21, 2004.

HEARING OR NOTIFICATION OF HEARING: An order granting the application will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Commission's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on July 19, 2004, and should be accompanied by proof of service on the applicants, in the form of an affidavit, or, for lawyers, a certificate of service. Hearing requests should state the nature of the writer's interest, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by writing to the Commission's Secretary.

ADDRESSES: Secretary, Commission, 450 Fifth Street, NW., Washington, DC 20549–06090; Applicants, c/o MMA Praxis Mutual Funds, 3435 Stelzer Roads, Columbus, OH 43219.

FOR FURTHER INFORMATION CONTACT: John Yoder, Attorney-Adviser, at (202) 942–0544, or Mary Kay Frech, Branch Chief, at (202) 942–0564 (Division of Investment Management, Office of Investment Company Regulation).

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application may be obtained for a fee at the Commission's Public Reference Branch, 450 Fifth Street, NW., Washington, DC 20549–0102 (telephone (202) 942–8090).

Applicant's Representations

1. The Trust, a Delaware statutory trust, is registered under the act as an open-end management investment company. The Trust is organized as a series investment company consisting of 4 series, two of which are the MMA Praxis Intermediate Income Fund ("Intermediate Income Fund") and MMA Praxis Core Stock Fund ("Core Stock Fund") (collectively, the "Mutual Funds"). The Intermediate Income Fund invests primarily in undervalued securities of medium to large capitalization companies. MMA, an Indiana corporation, is an investment adviser to the Mutual Funds pursuant to an investment advisory agreement with the Trust.

2. MF, a not-for-profit corporation organized under the laws of Indiana, is excluded from the definition of investment company under the Act pursuant to section 3(c)(10) of the Act. MF's board of directors manages and controls the business of MF. MF's portfolio securities are segregated by asset class and are held in separate accounts. Each separate account is a sub-account of MF and is not a legal entity separate from MF. Two of these sub-accounts, Common Stock Fund and Intermediate Bond Fund, are managed by MMA.

3. MRT, a qualified retirement plan, is excluded from the definition of investment company under the Act pursuant to section 3(c)(11) of the Act. MRT's board of trustees manages its investment activities. MRT's portfolio securities are segregated by asset class and are held in separate accounts. Each separate account is a sub-account of MRT and is not a legal entity separate from MRT. Two of these sub-accounts, Large Cap Blend Fund and Bond Fund, are managed by MMA. The directors/trustees of MRT and MF (collectively, the "Unregistered Funds") also serve as directors of Mennonite Mutual Aid, Inc., the controlling company of MMA.

4. Applicants seek relief to permit MRT and MF to transfer substantially all the assets in MRT's Bond Fund and MF's Intermediate Bond Fund, respectively, (the "Assets") to the Intermediate Income Fund in exchange for shares (the "Shares") of the Intermediate Income Fund. Applicants also propose that MRT and MF will transfer substantially all of the assets in MRT's Large Cap Blend Fund and MF's Common Stock Fund (included in the term, "Assets") to the Core Stock Fund in exchange for Shares of the Core Stock Fund. The Transfers are referred to, collectively, as the "Exchange".

5. The Assets of the Unregistered Funds contemplated for transfer to the Mutual Funds in the Exchange will consist of individual securities that are substantially similar to those held as investments by the Mutual Funds. The Assets will be valued by each Mutual Fund at the time of acquisition at the independent "current market price" of the securities as defined in rule 17a–7 under the Act, the same valuation procedures set forth in the Mutual Funds' registration statements. The Shares of the Intermediate Income Fund and the Core Stock Fund received in the Exchange will have an aggregate net asset value ("NAV") equal to the NAV of the Assets transferred by MF and MRT to the Intermediate Income Fund and the Core Stock Fund. The Unregistered Funds and the Mutual Funds will each pay their own expenses incurred in connection with the Exchange.

6. After the Exchange, MF's Common Stock Fund and Intermediate Bond Fund will not make any investments other than investments in shares of the Core Stock Fund and Intermediate Income Fund, respectively. Similarly, after the Exchange, MRT's Bond Fund and MRT's Large Cap Blend Fund will not make any investments other than investments in shares of Intermediate Income Fund and Core Stock Fund, respectively.

Applicants' Legal Analysis

1. Section 17(a) of the Act, in relevant part, prohibits an affiliated person of a registered investment company, or any affiliated person of such person, acting as principal, from selling to or purchasing from such investment company any security or other property.

2. Section 2(a)(3) of the Act defines an "affiliated person" of another person to include (a) any person directly or indirectly controlling, controlled by, or under common control with the other person and (b) if the other person is an investment company, any investment adviser of that company. Applicants state that the Unregistered Funds and MMA may be considered to be under common control because a majority of the directors/trustees serving on the Unregistered Funds' boards of directors/trustees also serve as directors of MMA. Applicants also state that the Unregistered Funds and the Mutual Funds may be considered to be under common control and therefore may be considered affiliated persons of each other under section 2(a)(3) of the Act. Thus, applicants state that the proposed

Exchange may be prohibited under Section 17(a) of the Act.

3. Rule 17a–7 exempts certain purchase and sale transactions otherwise prohibited by section 17(a) of the Act if an affiliation exists solely by reason of having a common investment adviser, investment advisers that are affiliated persons of each other, common directors, and/or common officers, provided, among other requirements, that the transaction is for no consideration other than cash. Applicants state that the relief provided by rule 17a–7 may not be available for the Exchange because the Exchange will involve consideration other than cash (*i.e.,* Shares of the Mutual Funds). Applicants also state that the Unregistered Funds may be deemed to be affiliated with the Mutual Funds for reasons other than those set forth in rule 17a–7.

4. Rule 17a–8 exempts certain transactions (including mergers, consolidations or purchases or sales of substantially all of the assets of a company) between registered investment companies and eligible unregistered funds, as defined in rule 17a–8 ("Eligible Unregistered Fund"). Applicants state that the relief provided by rule 17a–8 is not available for the Exchange because the Unregistered Funds are not registered investment companies or Eligible Unregistered Funds, and the Exchange does not involve substantially all of the assets of the Unregistered Funds.[1]

5. Section 17(b) of the Act provides that the Commission may exempt a transaction from the provisions of section 17(a) of the Act if the evidence establishes that the terms of the proposed transaction, including the consideration to be paid, are reasonable and fair and do not involve overreaching on the part of any person concerned, and that the proposed transaction is consistent with the policy of each registered investment company concerned and with the general purposes of the Act.

6. Applicants submit that the terms of the Exchange satisfy the standards set forth in section 17(b) of the Act. Applicants state that the board of the Trust, including a majority of the trustees who are not interested persons as defined in section 2(a)(19) of the Act, found that participation in the Exchange is in the best interests of each Mutual Fund and that the interests of the existing shareholders of each Mutual Fund will not be diluted as a result of the Exchange. Applicants state that the Exchange will comply with the terms of paragraphs (a) (other than the cash payment requirement) through (g) of rule 17a–7 and the provisions of rule 17a–8 (as those provisions apply to the merger of an Eligible Unregistered Fund with a registered investment company). No brokerage commissions, fees (except for customary transfer fees, if any) or other remuneration will be paid by the Mutual Funds or the Unregistered Funds in connection with the Exchange.

[1] Although the Exchange will involve substantially all of the assets of MF's Common Stock Fund and Intermediate Bond Fund and MRT's Bond Fund and Large Cap Blend Fund, these entities do not have an existence separate from the Unregistered Funds.

Applicants' Condition

Applicants agree that any order granting the requested relief will be subject to the following condition:

The Exchange will comply with the terms of paragraphs (a) (other than the cash payment requirement) through (g) of rule 17a–7 and the provisions of rule 17a–8 (as those provisions apply to the merger of an Eligible Unregistered Fund with a registered investment company).

For the Commission, by the Division of Investment Management, under delegated authority.

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–14675 Filed 6–28–04; 8:45 am]

BILLING CODE 8010–01–M

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49902; File No. SR–MSRB–2004–02]

Self-Regulatory Organizations; Notice of Filing of Proposed Rule Change by the Municipal Securities Rulemaking Board Relating to Proposed Amendments to the MSRB's Rule G–12(f) on Automated Comparison and G–14 on Transaction Reporting, and to the Implementation of a Facility for Real-Time Transaction Reporting and Price Dissemination

June 22, 2004.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 2, 2004, the Municipal Securities Rulemaking Board ("MSRB" or "Board") filed with the Securities and Exchange Commission ("SEC" or "Commission") the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the MSRB. 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).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The MSRB's proposed rule change relates to Rule G–14, on transaction reporting, Rule G–12(f), on automated comparison, and the implementation of a facility for real-time transaction reporting and price dissemination (the "Real-Time Transaction Reporting System" or "RTRS"). Below is the text of the proposed rule change. Proposed new language is in *italics;* proposed deletions are in brackets.

* * * * *

Rule G–12. Uniform Practice

(a)–(e) No change.

(f) Use of Automated Comparison, Clearance and Settlement Systems.

(i) Notwithstanding the provisions of sections (c) and (d) of this rule, [a] *an Inter-Dealer T*[t]ransaction *E*[e]ligible for [automated trade] *C*[c]omparison by a *C*[c]learing *A*[a]gency *R*[r]egistered with the [Securities and Exchange] Commission (registered clearing agency) shall be compared through a registered clearing agency. Each party to such a transaction shall submit or cause to be submitted to a registered clearing agency all information and instructions required from the party by the registered clearing agency for automated comparison of the transaction to occur. *Each transaction effected during the RTRS Business Day shall be submitted for comparison within 15 minutes of the Time of Trade, unless the transaction is subject to an exception specified in the Rule G–14 RTRS Procedures paragraph (a)(ii), in which case it shall be submitted for comparison in the time frame specified in the Rule G–14 RTRS Procedures paragraph (a)(ii). Transactions effected outside the hours of an RTRS Business Day shall be submitted no later than 15 minutes after the beginning of the next RTRS Business Day.* In the event that a transaction submitted to a registered clearing agency for comparison in accordance with the requirements of this paragraph (i) shall fail to compare, the party submitting such transaction shall, *as soon as possible,* use the [post-original-comparison] procedures provided by the registered clearing agency in connection with such transaction until such time as the transaction is compared or final notification of a failure to compare the transaction is received from the contra-party. *A broker, dealer or municipal securities dealer ("dealer") that effects inter-dealer transactions eligible for comparison by a clearing agency* *registered with the Commission shall ensure that submissions made against it in the comparison system are monitored for the purpose of ensuring that correct trade information alleged against it is acknowledged promptly and that erroneous information alleged concerning its side of a trade (or its side of a purported trade) is corrected promptly through the procedures of the registered securities clearing agency or the MSRB.*

(ii) No change.

(iii) No change.

(iv) Definitions.

(A) "Inter-Dealer Transaction Eligible for Comparison by a Clearing Agency Registered with the Commission" means a contract for purchase and sale between one dealer and another dealer, resulting in a contractual obligation for one such dealer to transfer municipal securities to the other dealer involved in the transaction, and which contract is eligible for comparison under the procedures of an automated comparison system operated by a registered clearing agency.

(B) "Time of Trade" is defined in Rule G–14 Transaction Reporting Procedures.

(C) The "RTRS Business Day" is defined in Rule G–14 RTRS Transaction Reporting Procedures.

Rule G–14. Reports of Sales or Purchases

(a) No change.

(b) Transaction Reporting Requirements.

(i) Each broker, dealer or municipal securities dealer *("dealer")* shall report to the Board or its designee information about [its] *each purchase and sale* transaction[s] *effected* in municipal securities to the *Real-time Transaction Reporting System ("RTRS") in the manner prescribed by Rule G–14 RTRS Procedures and the RTRS Users Manual* [extent required by, and using the formats and within the timeframes specified in, Rule G–14 Transaction Reporting Procedures]. Transaction information collected by the Board under this rule will be used to make public reports of market activity and prices and to assess transaction fees. The transaction information will be made available by the Board to the Commission, securities associations registered under Section 15A of the Act and other appropriate regulatory agencies defined in Section 3(a)(34)(A) of the Act to assist in the inspection for compliance with and the enforcement of Board rules.

(ii) The information specified in the [Transaction Reporting] *Rule G–14 RTRS* Procedures is critical to public reporting of prices for transparency purposes and to the compilation of an audit trail for regulatory purposes. All [brokers, dealers and municipal securities] dealers have an ongoing obligation to report this information promptly, accurately and completely. The [broker, dealer or municipal securities] dealer may employ an agent for the purpose of submitting [customer] transaction information; however the primary responsibility for the timely and accurate submission remains with the [broker, dealer or municipal securities] dealer that effected the transaction. *A dealer that acts as a submitter for another dealer has specific responsibility to ensure that transaction reporting requirements are met with respect to those aspects of the reporting process that are under the Submitter's control. A dealer that submits inter-dealer municipal securities transactions for comparison, either for itself or on behalf of another dealer, has specific responsibility to ensure that transaction reporting requirements are met with respect to those aspects of the comparison process that are under the Submitter's control.*

(iii) To identify its transactions for reporting purposes, each [broker, dealer and municipal securities] dealer shall obtain a unique [executing] broker symbol from the National Association of Securities Dealers, Inc.

(iv) Each dealer shall provide to the Board on Form RTRS information necessary to ensure that its trade reports can be processed correctly. Such information includes the manner in which transactions will be reported, the broker symbol used by the dealer, the identity of and information on any intermediary to be used as a Submitter, information on personnel that can be contacted if there are problems in RTRS submissions, and information necessary for systems testing with RTRS. Information provided on Form RTRS shall be kept current by notifying the MSRB when contact information or other information provided on the form changes.

(v) Testing Requirements.

(A) Prior to submitting transaction data under RTRS Procedures, a dealer must successfully test its ability to interface with RTRS as described in the RTRS Users Manual.

(B) Testing During RTRS Start-Up

(1) Testing facilities will be made available at least six months prior to the announced effective date of these transaction reporting procedures ("Announced RTRS Start-Up Date"). Except as provided in the subparagraph below, each dealer shall be prepared for testing no later than three months prior to the Announced RTRS Start-Up Date and shall either have successfully tested its RTRS capabilities or have scheduled a testing date with the MSRB by that time.

(2) A dealer electing to use only the Web-based trade input method of transaction reporting and that has averaged submissions of five or fewer trades during a one-year period beginning in July 2003 shall be required to test its RTRS capabilities no later than one month prior to the Announced RTRS Start-Up Date.

(vi) The following transactions shall not be reported under Rule G–14:

(A) Transactions in securities without assigned CUSIP numbers;

(B) Transactions in Municipal Fund Securities; and

(C) Inter-dealer transactions for principal movement of securities between dealers that are not inter-dealer transactions eligible for comparison in a clearing agency registered with the Commission.

Rule G–14RTRS [Transaction Reporting] Procedures

[(a) Inter-Dealer Transactions.]

[(i) Except as described in paragraph (ii) of this section (a), each broker, dealer and municipal securities dealer shall report all transactions with other brokers, dealers or municipal securities dealers to the Board's designee for receiving such transaction information. The Board has designated National Securities Clearing Corporation (NSCC) for this purpose. A broker, dealer or municipal securities dealer shall report a transaction by submitting or causing to be submitted to NSCC information in such format and within such timeframe as required by NSCC to produce a compared trade for the transaction in the initial comparison cycle on the night of trade date in the automated comparison system operated by NSCC. Such transaction information may be submitted to NSCC directly or to another registered clearing agency linked for the purpose of automated comparison with NSCC.]

[The information submitted in accordance with this procedure shall include the time of trade execution and the identity of the brokers, dealers, or municipal securities dealers that execute the transaction in addition to the identity of the entities that clear the transaction. If clearing/introducing broker arrangements are used for transactions, the introducing brokers shall be identified as the "executing brokers." If the settlement date of a transaction is known by the broker, dealer or municipal securities dealer, the report made to NSCC also shall include a value for accrued interest in the format prescribed by NSCC.]

[(ii) A transaction that is not eligible to be compared in the automated comparison system operated by NSCC (because of the lack of a CUSIP number for the security or other reasons) shall not be required to be reported under this section (a). A transaction that is subject to a "one-sided" submission procedure in the automated comparison system operated by NSCC shall be reported only by the broker, dealer or municipal securities dealer that is required to submit the transaction information under the one-sided submission procedure.]

[(b) Customer Transactions]

[(i) Each broker, dealer and municipal securities dealer shall report to the Board all transactions with customers effected after March 1, 1998, except as described in paragraph (iii) of this section (b). A broker, dealer or municipal securities dealer shall report a transaction by submitting or causing to be submitted to the Board, by midnight of trade date, the customer transaction information specified in paragraph (ii) of this section (b) in such format and manner specified in the current User's Manual for Customer Transaction Reporting. The broker, dealer or municipal securities dealer shall promptly report cancellation of the trade or corrections to any required data items.]

[(ii) The information submitted in accordance with this procedure shall include: the CUSIP number of the security; the trade date; the time of trade execution; the executing broker symbol identifying the broker, dealer or municipal securities dealer that effected the transaction; a symbol indicating the capacity of the broker, dealer or municipal securities dealer as buyer or seller in the transaction; the par value traded; the dollar price of the transaction, exclusive of any commission; the yield of the transaction; a symbol indicating the capacity of the broker, dealer or municipal securities dealer as agent for the customer or principal in the transaction; the commission, if any; the settlement date, if known to the broker, dealer or municipal securities dealer; a control number, determined by the broker, dealer or municipal securities dealer, identifying the transaction; and a symbol indicating whether the trade has previously been reported to the Board, and, if so, the control number used by the broker, dealer or municipal securities dealer for the previous report.]

[(iii) The following transactions shall not be required to be reported under this section (b):

(A) a transaction in a municipal security that is ineligible for assignment of a CUSIP number by the Board or its designee; and

(B) a transaction in a municipal fund security.]

[(iv) Each broker, dealer and municipal securities dealer effecting customer transactions in municipal securities, including introducing and clearing brokers, shall provide to the Board the name and telephone number of a person responsible for testing that firm's capabilities to report customer transaction information. Each broker, dealer or municipal securities dealer shall test such capabilities in a manner and according to the requirements specified in the current User's Manual for Customer Transaction Reporting. This paragraph (iv) shall take effect July 1, 1997.]

(a) General Procedures.

(i) The Board has designated three RTRS Portals for dealers to use in the submission of transaction information. Transaction data submissions must conform to the formats specified for the RTRS Portal used for the trade submission. The RTRS Portals may be used as follows:

(A) The message-based trade input RTRS Portal operated by National Securities Clearing Corporation (NSCC) ("Message Portal") may be used for any trade record submission or trade record modification.

(B) The RTRS Web-based trade input method ("RTRS Web Portal" or "RTRS Web") operated by the MSRB may be used for low volume transaction submissions and for modifications of trade records, but cannot be used for submitting or amending inter-dealer transaction data that is used in the comparison process. Comparison data instead must be entered into the comparison system using a method authorized by the registered clearing agency.

(C) The NSCC Real-Time Trade Matching ("RTTM") Web-based trade input method ("RTTM Web Portal" or "RTTM Web") may be used only for submitting or modifying data with respect to Inter-Dealer Transactions Eligible for Comparison.

(ii) Transactions effected with a Time of Trade during the hours of the RTRS Business Day shall be reported within 15 minutes of Time of Trade to an RTRS Portal except in the following situations:

(A) Syndicate managers, syndicate members and selling group members that effect trades in new issues on the first day of trading at the list offering price shall report such trades by the end of the day on which the trades were executed.

(B) A dealer effecting trades in short-term instruments under nine months in effective maturity, including variable rate instruments, auction rate products, and commercial paper shall report such trades by the end of the RTRS Business Day on which the trades were executed.

(C) A dealer shall report a trade within three hours of the Time of Trade if all the following conditions apply: (1) The CUSIP number and indicative data of the issue traded are not in the securities master file used by the dealer to process trades for confirmations, clearance and settlement; (2) the dealer has not traded the issue in the previous year; and (3) the dealer is not a syndicate manager or syndicate member for the issue. If fewer than three hours of the RTRS Business Day remain after the Time of Trade, the trade shall be reported no later than 15 minutes after the beginning of the next RTRS Business Day. This provision (C) will cease to be effective one year after the Announced RTRS Start-Up Date.

(iii) Transactions effected with a Time of Trade outside the hours of the RTRS Business Day shall be reported no later than 15 minutes after the beginning of the next RTRS Business Day.

(iv) Transaction data that is not submitted in a timely and accurate manner in accordance with these Procedures shall be submitted or corrected as soon as possible.

(v) Information on the status of trade reports in RTRS is available through the Message Portal, through the RTRS Web Portal, or via electronic mail. Trade status information from RTRS indicating a problem or potential problem with reported trade data must be reviewed and addressed promptly to ensure that the information being disseminated by RTRS is as accurate and timely as possible.

(vi) RTRS Portals will be open for transmission of transaction data and status of trade reports beginning 30 minutes prior to the beginning of the RTRS Business Day and ending 90 minutes after the end of the RTRS Business Day.

(b) Reporting Requirements for Specific Types of Transactions.

(i) Inter-Dealer Transactions Eligible for Comparison by a Clearing Agency Registered with the Commission.

(A) Bilateral Submissions: Inter-Dealer Transactions Eligible for Trade Comparison at a Clearing Agency Registered with the Commission (registered clearing agency) shall be reported by each dealer submitting, or causing to be submitted, such

transaction records required by the registered clearing agency to achieve comparison of the transaction. The transaction records also shall include the additional trade information for such trades listed in the Specifications for Real-Time Reporting of Municipal Securities Transactions contained in the RTRS Users Manual.

(B) Unilateral Submissions: For transactions that, under the rules of the registered clearing agency, are deemed compared upon submission by one side of the transaction (unilateral submissions), a submission is not required by the contra-side of the transaction. The contra-side, however, must monitor such submissions to ensure that data representing its side of the trade is correct and use procedures of the registered clearing agency to correct the trade data if it is not.

(ii) Customer Transactions. Reports of transactions with customers shall include the specific items of information listed for such transactions in the Specifications for Real-Time Reporting of Municipal Securities Transactions.

(iii) Agency Transactions With Customers Effected By An Introducing Broker Against Principal Account of its Clearing Broker. Reports of agency transactions effected by an introducing broker for a customer against the principal account of its clearing broker shall include the specific items of information listed in the Specifications for Real-Time Reporting of Municipal Securities Transactions for "Inter-Dealer Regulatory-Only" trades.

(c) RTRS Users Manual. The RTRS Users Manual is comprised of the Specifications for Real-Time Reporting of Municipal Securities Transactions, the Users Guide for RTRS Web, Testing Procedures, guidance on how to report specific types of transactions and other information relevant to transaction reporting under Rule G–14. The RTRS Users Manual is located at www.msrb.org and may be updated from time to time with additional guidance or revisions to existing documents.

(d) Definitions.

(i) "RTRS" or "Real-Time Transaction Reporting System" is a facility operated by the MSRB. RTRS receives municipal securities transaction reports submitted by dealers pursuant to Rule G–14, disseminates price and volume information in real time for transparency purposes, and otherwise processes information pursuant to Rule G–14.

(ii) The "RTRS Business Day" is 7:30 a.m. to 6:30 p.m., Eastern Time, Monday through Friday, on each business day as defined in Rule G–12(b)(i)(B).

(iii) "Time of Trade" is the time at which a contract is formed for a sale or purchase of municipal securities at a set quantity and set price.

(iv) "Submitter" means a dealer, or service bureau acting on behalf of a dealer, that has been authorized to interface with RTRS for the purposes of entering transaction data into the system.

(v) "Inter-Dealer Transaction Eligible for Automated Comparison by a Clearing Agency Registered with the Commission" is defined in MSRB Rule G–12(f)(iv).

(vi) "Municipal Fund Securities" is defined in Rule D–12.

* * * * *

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the MSRB included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The MSRB has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to increase transparency and to enhance the surveillance database and audit trail of transaction data used by enforcement agencies. The proposed rule change contains draft amendments to MSRB rules that would require brokers, dealers and municipal securities dealers ("dealers") to report transactions in municipal securities to RTRS within 15 minutes of the time of trade execution instead of by midnight on trade date, as is currently required. Upon receipt of this transaction data, RTRS would immediately perform automated error checking and would electronically disseminate prices, providing the municipal securities market with real-time transaction price transparency.

The proposed RTRS facility for real-time collection and dissemination of transaction prices is planned to become operational in January 2005, at which time MSRB would begin to disseminate transaction data electronically in real time. MSRB expects to make a second filing on the RTRS facility in the future, stating the date of effectiveness, describing the technical means of data dissemination, and proposing fees to be charged for RTRS data products.

The proposed RTRS facility would replace the existing Transaction Reporting System (TRS), which currently receives and disseminates transaction data in an overnight batch process. The proposed amendments to Rules G–12 and G–14 require dealer participation in RTRS and are designed to ensure that transactions are reported to RTRS in a timely manner. The proposed amendments are described in section (ii) below and the proposed RTRS facility is described in section (iii) below.

(i) *Overview.* The Board has a long-standing policy to increase price transparency in the municipal securities market, with the ultimate goal of disseminating comprehensive and contemporaneous pricing data.[3] The Board implemented a limited transaction reporting facility (the "Transaction Reporting System" or "TRS") for the municipal securities market in 1995 and has since increased price transparency in the municipal securities market in measured steps.[4]

[3] *See* "Planned Pilot Program for Publishing Inter-Dealer Transaction Information," *MSRB Reports*, Vol. 13, No. 3 (June 1993) at 3 and "Board to Proceed with Pilot Program to Disseminate Inter-Dealer Transaction Information," *MSRB Reports*, Vol. 14, No. 1 (January 1994) at 13.

[4] The MSRB's first public price transparency report, the T+1 Daily Report, was initiated in 1995. It was disseminated daily on the day after trade date and summarized high, low and average inter-dealer prices for issues that met a trading threshold of four or more trades in the inter-dealer market. *See* Release Number 34–34955 (November 9, 1994), 59 FR 59810 (November 18, 1994). In 1998, the MSRB added customer trade data to the report. *See* Rel. No. 34–37998 (November 29, 1996), 61 FR 64782, and Rel. No. 34–40349 (August 20, 1998), 63 FR 45545. In January 2000, the MSRB further enhanced the T+1 Daily Report by publishing individual transaction data (rather than high, low and average prices) for each issue that met the threshold of four or more trades. *See* Rel. No. 34–42241 (December 16, 1999), 64 FR 72123. In October 2000 the MSRB began disseminating a Monthly Comprehensive Report, which lists all municipal securities transactions regardless of frequency of trading. This report covers all trades done during the previous month and includes late-reported trades, inter-dealer trades compared after trade date, and transaction data corrected by dealers after trade date, as well as infrequently traded issues. *See* Rel. No. 34–43426 (October 10, 2000). In October 2001, the MSRB began disseminating a Daily Comprehensive Report of all trades done on a single day two weeks earlier. *See* Rel. No. 34–44894 (October 2, 2001), 65 FR 61367. As the market became familiar with these reports, the MSRB began the process of lowering the trading threshold in the T+1 Daily Report to make more trade data available on a T+1 basis. In May 2002, the MSRB changed the trading threshold for the T+1 Daily Report to three trades. *See* Rel. No. 34–45861 (May 1, 2002), 67 FR 30989. In August 2002, the delay for the Daily Comprehensive Report was changed from two weeks to one week. At the same time, the MSRB

The proposed rule change represents the final stage of the evolution of price transparency in the municipal securities market, which is a system for comprehensive, real-time price dissemination.

The Board believes that a number of benefits to the market will accrue as a result of making real-time price information available, including more efficient pricing and enhanced investor confidence. The MSRB recognizes that, because of the unique features of the municipal securities market, real-time price transparency for municipal securities will not necessarily function in the same manner as in the major equity markets. Since less that one percent of outstanding municipal securities trade on a given day, an investor holding municipal securities often will not be able simply to view "last sale" information to obtain an exact market price, as generally can be done for exchange-traded or NASDAQ listed stocks. Nevertheless, real-time prices will provide important information on the market conditions for individual securities that are trading on a given day, and this information often can be extrapolated to assist in the accurate valuation of similar municipal issues that are not actively traded on a given day.

With respect to efficiency of pricing mechanisms, the transaction data available from TRS show that, while much of the market trades within a narrow range, there are instances in which intra-day prices for specific issues vary substantially, even when no apparent news or transaction size differences account for the different valuations. This fact is not intended to suggest that instances of substantial intra-day price volatility would be eliminated by real-time price transparency, particularly when the market is assimilating new information about interest rates or the credit quality of specific issues. However, the transaction data do suggest that the efficiency of pricing in some cases might be improved substantially if prices are made accessible on a real-time basis, as is done in many other securities markets. In general, real-time price transparency should benefit the market by helping to ensure that information relevant to the value of municipal securities issues is incorporated more quickly and reliably into transaction prices.

The Board also believes that real-time price transparency will enhance investor confidence by providing, for the first time, a comprehensive and contemporaneous view of the market, accessible to any interested party. There is a significant demand by sophisticated investors to see where municipal bonds are trading as part of their research and investment strategies for fixed-income products. Real-time price transparency will increase confidence that the best market price for specific securities has been located. For both institutional and retail investors, the open availability of market prices should instill greater confidence that pricing mechanisms in the market are fair, open and efficient.

(ii) *Proposed Amendments to Rules G–12(f) and G–14.* As discussed below, the procedures for dealers to report inter-dealer transactions to RTRS are integrated with the central comparison system to provide a cost-effective mechanism for dealers to report transactions in real-time.[5] The proposed rule change thus includes amendments both to Rule G–14 on transaction reporting and Rule G–12(f) on automated comparison. The Rule G–14 Procedures would also be amended.

Rule G–12(f). Rule G–12(f)(i) currently requires that an inter-dealer transaction eligible for automated trade comparison through the facilities of a clearing agency registered with the Commission ("registered clearing agency") shall be compared through a registered clearing agency. Each party to the transaction must submit or cause to be submitted to the registered clearing agency all the information required by the registered clearing agency for automated comparison to occur. If a transaction fails to compare, the parties must use the procedures provided by the registered clearing agency to attain comparison, unless one of the parties provides the other with final notification of failure to compare. (Sections (ii) and (iii) of Rule G–12(f) pertain to other aspects of clearance and settlement unchanged by the proposed amendment.)

The proposed amendment to Rule G–12(f)(i) would contain a new requirement that inter-dealer trades effected during the RTRS Business Day, when eligible for automated comparison, be submitted to a registered clearing agency within 15 minutes of the time of trade. The RTRS Business Day (7:30 a.m. through 6:30 p.m.)[6] is defined in proposed Rule G–14. There would be limited exceptions to the 15-minute requirement, as detailed below. The proposed amendment would add a requirement, identical to that in the proposed amendment to Rule G–14, that inter-dealer trades effected outside the hours of the RTRS Business Day be submitted for comparison within 15 minutes of the start of the next RTRS Business Day. It also notes a dealer's obligation to monitor submissions made against it in the real-time comparison system and to use the procedures provided by the clearing agency to address any erroneous information concerning its side of a transaction that may be submitted by a contra-party.

Rule G–14 and Rule G–14 Procedures. The current Rule G–14 and the associated Rule G–14 Procedures require that dealers report their trades to the MSRB by midnight of trade date. The existing Rule G–14 Procedures exempt from reporting requirements transactions in municipal securities that are ineligible for assignment of a CUSIP number, transactions in municipal fund securities and the (rare) inter-dealer transactions that are not eligible for automated comparison. The current Rule G–14 Procedures also require each dealer to provide to the MSRB information about a person responsible for testing the dealer's capabilities to report customer transactions, and require the dealer to conduct such testing.

The proposed amendment to Rule G–14 would require the dealer to report information about its transactions to the MSRB or its designee in the manner required by RTRS Transaction Reporting Procedures, which in most cases require the report to be made within 15 minutes of the time of trade execution. The proposed amendment would retain without change the prohibition against reporting fictitious or fraudulent transactions, the statement of the

began disseminating a daily report of all trades done on a single day one month earlier, to enable users of the report to update their databases each day with trades reported or corrected more than one week after trade date. *See* Rel. No. 34–46380 (August 19, 2002), 67 FR 54831. In November 2002, the MSRB changed the trading threshold for the T+1 Daily Report from three trades to two trades. *See* Rel. No. 34–46819 (November 12, 2002), 67 FR 69779. In June 2003, the trading threshold was dropped and all T-submitted trades were disseminated on T+1. At the same time, the display of par values on this report were changed to show the exact par for trades of $1 million or less and "1MM+" for par over $1 million. *See* Rel. No. 34–47888 (May 19, 2003), 68 FR 28865.

[5] Automated comparison, which is required for inter-dealer transactions by rule G–12(f)(i), is accomplished by a clearing corporation registered with the Commission under section 17A of the Act. It is the first step in the clearance and settlement of an inter-dealer transaction and generally involves the matching of trade data submitted by both sides of an inter-dealer trade. Only one registered securities clearing corporation—National Securities Clearing Corporation—compares municipal securities transactions and is thus a central point for trade data in the municipal securities market. Consequently, the Board chose to use NSCC as the main portal for RTRS data submission and, with respect to inter-dealer transactions, to allow the comparison submission to also serve the purpose of transaction reporting.

[6] All times given are Eastern.

purpose of transaction reporting, and the requirement for the dealer to obtain an identifying symbol.

As in the current transaction reporting system, a dealer will be able to use an intermediary, *e.g.*, its clearing broker, to submit transaction reports. The MSRB expects those dealers that are not self-clearing to submit inter-dealer trades through their clearing broker as they do today. The language articulating dealer responsibility for timely and accurate reporting is clarified in the proposed amendment, reflecting existing policy of the MSRB. It notes that, while the dealer that effected the transaction has the primary responsibility to ensure timely and accurate transaction reporting, any dealer that submits information for transaction reporting on behalf of another dealer has a specific responsibility to ensure that transaction reporting requirements are met with respect to the activities under the dealer's control.

The proposed amendment would require each dealer to provide the MSRB with information needed to process transactions correctly on a new form, Form RTRS. The dealer would indicate thereon the method it will use to submit trade reports, its broker symbol, the identity of any intermediary or agent it will use to report transactions, contact information for dealer testing and operations staff and whether the dealer acts in the capacity of a broker's broker.[7] The proposed amendment also continues to maintain the current exemptions for transactions in municipal securities that are ineligible for assignment of a CUSIP number, transactions in municipal fund securities and the (rare) inter-dealer transactions that are not eligible for automated comparison.

Finally, as in the current Rule G–14 Procedures, a mandatory testing requirement is included in the proposed amendment. Testing would be required of dealers making the transition from the current Transaction Reporting System to RTRS, and also would be required of dealers that begin reporting transactions in the future. The MSRB will make testing facilities available to dealers at least six months before the announced effective date of the Proposed Rule Change ("Announced RTRS Start-Up Date"). Each dealer will have to be prepared to test its use of RTRS no later than three months before the Announced RTRS Start-Up Date and must schedule a test date by that time unless it has already successfully tested its RTRS capabilities. However, dealers that have effected an average of five or fewer transactions per week during the preceding year and that will use only the Web-based method must successfully test their RTRS capabilities one month before the Announced RTRS Start-Up Date.

The proposed RTRS Procedures would replace the current Rule G–14 Procedures used for TRS data submission with a new set of requirements specific to RTRS. The RTRS Procedures generally would require dealers to report trades to the MSRB within 15 minutes, using either a message-based or Web-based reporting method.[8] The 15-minute requirement would apply to all reportable trades effected during the RTRS Business Day, with the following limited exceptions:

- Syndicate managers, syndicate members and selling group members that effect trades in new issues at the list offering price would be required to report such trades by the end of the first day of trading in the issue.
- Dealers would be required to report trades in short-term issues such as variable rate instruments, auction rate products, and commercial paper by the end of the day in which the trades are effected.
- On a temporary basis, a dealer would be required to report trades within three hours of the time of trade if the CUSIP number and indicative data of the issue traded are not in the dealer's securities master file, the dealer has not traded the issue in the previous year, and the dealer is not a syndicate manager or syndicate member for the issue. This provision would sunset automatically one year after RTRS implementation.

The Board established the above exceptions after it received a number of comments on its exposure draft of the proposed rule change that indicated that dealers would face serious and in some cases insurmountable operational challenges in processing and reporting the above types of trades within 15 minutes using the processing systems available at this time. The challenges that are the basis for the reporting exceptions are discussed further in the section discussing comments received on the proposed rule change.

Under the proposed amendment to Rule G–14, trades effected outside the RTRS Business Day would have to be reported no later than 15 minutes after the beginning of the next Business Day. RTRS will be available to receive trade reports for at least 90 minutes after the end of an RTRS Business Day and at least 30 minutes before the beginning of the next RTRS Business Day, *i.e.*, from 7:00 a.m. through 8:00 p.m.[9] The RTRS Procedures would require that a dealer that does not submit transaction data in a timely or accurate manner must submit or correct the data as soon as possible. RTRS will provide to the submitter of data an indication of the status of each trade, *i.e.*, whether an error has been found in the input. The effecting dealer (and its clearing broker that submits data, if any) would be required to monitor the status of each trade report as shown in RTRS, and to review and address any problem or potential problem.

The RTRS Procedures provide specific requirements for reporting different types of transactions. As is the case currently in TRS, if an inter-dealer transaction is eligible for comparison at a registered clearing agency, the dealer or its clearing broker would satisfy the transaction reporting requirement by submitting the transaction to the registered clearing agency to achieve comparison. The inter-dealer trade submission would have to satisfy the requirements of the registered clearing agency and would have to include the additional information required by the MSRB in its *Specifications for Real-Time Reporting of Municipal Securities Transactions*.[10] To achieve comparison, both parties to the inter-dealer trade would have to submit or cause to be submitted a trade report to the registered clearing agency, unless the trade is one deemed by the clearing agency to be compared upon submission by the party on one side of the trade (unilateral submission).[11] The contra-

[7] Broker's brokers are dealers that hold themselves out to effect transactions exclusively between dealers, on an agency or riskless principal basis, and that do not take inventory positions in municipal securities. A broker's broker therefore always has matched purchase and sale transactions in the inter-dealer market. The requirement for a dealer to designate whether it is acting as a broker's broker will be used to mark transaction reports disseminated by RTRS. This is done to allow RTRS data users to distinguish these matched trades from other inter-dealer trading activity.

[8] In using the message-based method of trade reporting, the dealer would send electronic messages containing trade data from the dealer's computer to NSCC and receive interactive feedback, also as electronic messages. NSCC would act as a "portal," relaying the messages to and from the MSRB's RTRS. Each trade would be reported with a message. In using the Web-based method, the dealer would enter trade data to RTRS through an Internet browser on the dealer's personal computer and would receive RTRS feedback that would appear on the screen. These two methods are further described in connection with the proposed Facility.

[9] As noted below, submissions may be made to RTRS via the Internet from 6:00 a.m. to 9:00 p.m.

[10] *See* "Revised Specifications for the Real-Time Transaction Reporting System, Version 1.2," MSRB Notice 2004–2 (January 23, 2004), on *www.msrb.org*.

[11] For example, currently only the syndicate manager is required by NSCC to report its sales of

party would not be required to report a trade subject to unilateral submission but, to ensure the accuracy of trade information in RTRS, would be required to monitor such submissions against it to ensure that the data submitted against it is correct, and to use procedures of the registered clearing agency to correct the trade data if it is not.

Also similar to existing TRS requirements, transactions with customers would be reported by including the information required by the *Specifications for Real-time Reporting of Municipal Securities Transactions*. The extended reporting deadlines for new issue securities traded at the list price, securities not traded in the previous year and variable-rate securities would apply to customer transactions in the same way as they would to inter-dealer transactions.

The RTRS Procedures contain a new requirement that an agency trade effected for a customer by an introducing broker against the principal account of its clearing broker must be reported with data including the identity and role of the clearing broker. The information that will be required in this "inter-dealer regulatory-only" ("IDRO") report is nearly the same as that in a unilateral submission of an inter-dealer trade. The IDRO reporting requirement represents a change from the existing transaction reporting system for municipal securities, in which the introducing broker reports an agency transaction with the customer, but no report is made of the offsetting side of the agency transaction if it is executed against the clearing broker's account. The change is being made at the request of NASD to provide a more complete audit trail for surveillance purposes, and is further described below in connection with the enhancements that will be available to regulators in the real-time environment. This change also provides greater consistency with the manner in which similar transactions are handled in the TRACE transaction reporting system for corporate bonds.

RTRS will also have new requirements for dealers to report indicators to show: "special condition" trades that might be effected at a price other than the market price. The dealer would provide a code identifying the reason for the special condition, such as that a trade was done "flat." These indicators will enhance the market surveillance functions of the current reporting system and are described below in the section, "Enhancement of information available to regulators."

The *RTRS Users Manual* will give detailed guidance on how specific trading situations are handled and will include the *Specifications for Real-Time Reporting of Municipal Securities Transactions*,[12] the *Users Guide for RTRS Web*, and the *Testing Procedures*. The Users Manual will be located at *www.msrb.org* and may be updated from time to time.

(iii) *Proposed RTRS Facility*.

The MSRB has coordinated its plans for the RTRS facility with the new real-time comparison system for municipal and corporate bonds (the "Real-Time Trade Matching" or "RTTM" system) now being implemented by National Securities Clearing Corporation (NSCC).[13] The use of the NSCC telecommunication facility as a data collection point or "Portal" for transaction data and the use of a standard common format for trade reporting and automated comparison through NSCC are intended to reduce dealer costs in complying with the 15-minute transaction reporting requirement. Retail and institutional customer transactions and IDRO reports also will be reported through NSCC using the same record format as used for inter-dealer trades.[14] NSCC will not process customer transactions in the comparison system, but will forward the data to the MSRB and thus allow dealers to avoid setting up separate telecommunications links and facilities specifically for trade reporting to the MSRB.[15] In this manner NSCC and MSRB have attempted to provide a means for dealers to leverage their systems development work to satisfy two goals at once—that of real-time transaction reporting and real-time comparison of inter-dealer transactions. In this regard, the development plans for both systems have been coordinated to provide the greatest efficiencies possible for dealers.

Improved Functionality. The objective of real-time transaction reporting is to make price and volume information publicly available as soon as possible after trades are executed. Real-time reporting will also bring improved functionality to dealers and enforcement agencies, compared with the current batch-oriented reporting system. These improvements include:

- The ability to correct regulatory data, such as time of trade, on inter-dealer trade reports;
- The ability for a dealer to ensure the accuracy of regulatory information such as the time of trade, even when that information is reported on its behalf by a clearing broker;
- The capability for dealers to report their capacity as agent in inter-dealer trades; and
- Improvements in the "audit trail" of trade information.

Submission of Transaction Reports by Intermediaries. As in the current transaction reporting system, a dealer will be able to use an intermediary, *i.e.*, its clearing broker or service bureau, to submit transaction reports to RTRS. Also following current policies, inter-dealer transaction reporting and comparison will be accomplished using one transaction report. The MSRB expects those dealers that are not self-clearing to submit inter-dealer trades through their clearing broker as they do today. However, these dealers must ensure that the clearing broker will be able to submit the trade report satisfying both comparison and transaction reporting requirements within 15 minutes of the time of trade. Both dealers in this case will have the responsibility to work together to ensure that such trade submissions are timely and accurate. It will be possible for the correspondent to submit customer trade reports directly to the MSRB or for the clearing broker to submit on the correspondent's behalf.

Message-Based and Web-Based Input Methods. Two format options will be available for submission of data into RTRS: 1) message-based trade input, and 2) Web-based trade input. In message-based trade input, each trade is submitted as a "message" in a standardized format. A trade input message consists of a sequence of data tags and data fields—for example, the tag "SETT" followed by a date field indicates the settlement date of the trade. For real-time trade reporting and comparison, the format standard is the ISO 15022 format established by the International Organization for Standardization.[16] Each message is sent

new issue securities to syndicate members. NSCC deems such a trade compared on receipt of the syndicate manager's submission.

[12] *See* "Revised Specifications for the Real-Time Transaction Reporting System, Version 1.2," MSRB Notice 2004–2 (January 23, 2004), on *www.msrb.org*.

[13] NSCC is a clearing agency registered under the Act.

[14] For RTTM message specifications, *see* *Interactive Messaging: NSCC Participant Specifications for Matching Input and Output Version 1.0* (March 31, 2003), and "Modifications to RTTM Messaging Specifications," FICC CMU RTTM New Project Update Issue 6 (April 20, 2004), on *www.ficc.com*.

[15] By agreement with the MSRB, NSCC will not charge dealers for serving as the portal for customer transaction data, but MSRB will reimburse NSCC for any system costs that are attributable exclusively to this function.

[16] The ISO 15022 format is also used by NSCC's parent organization, the Fixed Income Clearing

Continued

as a separate unit between two computers. The fact that a trade message is the basic telecommunications unit enables real-time reporting, comparison and interactive feedback. Messages are well-suited to automated high-volume operations and to "straight-through processing" methods.

In using the Web-based method, the dealer manually accesses a Web site through an Internet browser to enter, correct or view trade data. As described below, different Web sites are used depending whether the data is entered for both comparison and regulatory reporting or only for reporting purposes. The Web-based method requires no system development work beyond setting up an Internet connection and obtaining the appropriate user ID, password and security safeguards. However, Web input is manual and it will not be possible to interface the Web-based method with the dealer's processing system. Therefore, exclusive use of the Web-based method for submitting transactions generally will be appropriate only for relatively low-volume submitters.

For high-volume submitters of transaction data, such as large dealers, clearing brokers and service bureaus, the only efficient and practical means for initial trade submission is likely to be message-based. The extent of systems work necessary for interfacing with RTRS (and with RTTM) in this case will be dependent in large part on whether the submitter currently captures trade data in real time for processing. Submitters that have prepared for real-time transaction reporting and comparison by converting from overnight batch processing systems to ones with a more real-time or straight-through processing approach should find the necessary systems changes comparatively minor.

Dealers may use the message-based method, the Web-based method, or both. Some high-volume dealers may submit the initial trade report as a message, review their submission and the RTRS status information on a Web site, and make corrections manually using Web-based trade input. Instead of using the Web, dealers may also submit corrections in message format. Alternatively, some low-volume dealers may use the message-based system if messaging is made available to them by clearing brokers or service bureaus.[17]

RTRS Portals. In the proposed amendment to the G–14 RTRS Transaction Reporting Procedures, the MSRB has designated three RTRS "Portals" for the receipt of municipal securities trade data. Each Portal has a different policy governing the type of trade data it can accept. Message-based trade input must go through the Message Portal, but Web-based trade input may go through either the RTRS Web Portal or the RTTM Web Portal.

• The Message Portal is operated by NSCC and accepts any type of municipal security trade submission or modification. All trade messages that the dealer indicates should be forwarded to RTRS will be relayed to RTRS by NSCC. In addition, messages that the dealer indicates should be processed by the comparison system will be routed to RTTM.[18]

• The RTRS Web Portal is operated by the MSRB and accepts any municipal security trade submission or modification except data that would initially report or modify inter-dealer transaction data used in the comparison process. (Comparison data instead must be entered into the comparison system using a method authorized by NSCC such as the Message Portal or the RTTM Web Portal). The RTRS Web Portal may be used to report or correct (a) customer trade data, (b) IDRO data, and (c) inter-dealer trade data, but only if that data is not used in comparison. For example, a dealer may use the RTRS Web Portal to correct an inter-dealer trade record with regard to the time of trade or dealer capacity, but not to correct (or to input initially) the CUSIP number, par or price of the trade.

• The RTTM Web Portal is operated by NSCC for comparison purposes.[19] It may be used to report or correct both "comparison data" (CUSIP number, par, price, etc.) and "regulatory reporting data" (time of trade, etc.), if that data is associated with an inter-dealer transaction eligible for comparison. The RTTM Web Portal may not be used to report or correct customer or IDRO trade records.

All RTRS Portals will be open to receive trade data for at least 90 minutes after the end of an RTRS Business Day and 30 minutes before the beginning of the next Business Day, *i.e.*, they will be open at least from 7 a.m. through 8 p.m. The RTRS Web Portal will be open for an additional 60 minutes at the beginning and end of the RTRS Business Day, *i.e.*, it will be open from 6 a.m. to 9 p.m.

Measurement of Timely Reporting. The time taken to report the trade will be measured by comparing the time of trade reported by the dealer with the time of receipt of the trade report at the designated RTRS Portal. RTRS will assess each trade against its reporting deadline (15 minutes, three hours, or end-of-day). Trades not received by the appropriate reporting deadline will be considered late.

Enhancement of Information Available to Regulators. MSRB has worked with NASD and other regulators to improve the audit trail and other surveillance capabilities that will be available once data is collected on a real-time basis. Some of these changes will require modifications or additions to existing transaction reporting procedures observed by dealers. One addition concerns the situation in which one dealer passes an order to a second dealer for execution directly out of the second dealer's principal account, with settlement made directly between the second dealer and the party placing the order. The situation requiring this "Inter-Dealer Regulatory-Only" or "IDRO" report typically occurs when a fully disclosed introducing broker submits a customer order to its clearing broker for execution, and the clearing broker executes and settles directly with the introducing broker's customer. The current TRS system requires only one trade report in this situation—a customer trade report from the introducing broker. RTRS procedures will require another trade report showing the identity and role of the clearing broker—it will be described as an Inter-Dealer Regulatory-Only transaction. The new trade report was requested by the NASD to provide a more complete audit trail for surveillance purposes.[20]

The current transaction reporting procedures require a dealer effecting a trade "as agent" for a customer to designate its capacity on the customer trade report. This requirement will remain in RTRS. Inter-dealer transaction reports currently do not require a capacity field to show whether the inter-dealer trade was done as agent for a

Corporation, for processing government, mortgage-backed, corporate, and unit interest trust securities.

[17] *See* "Operational Overview of MSRB's Real-Time Transaction Reporting System," MSRB Notice 2003–13 (April 7, 2003), on *www.msrb.org*.

[18] Use of the Message Portal for trade comparison is currently restricted to NSCC participants.

[19] Use of the RTTM Web Portal is restricted to NSCC participants.

[20] To satisfy the need for this audit trail requirement the execution of the order by the clearing broker for the correspondent will be considered to constitute an inter-dealer "transaction" between the two dealers even though no principal position transfers between the two dealers. (The principal position in these situations moves directly from the clearing broker to the customer.) If a principal position does transfer between dealers, the trade is an "Inter-dealer Transaction Eligible for Comparison," and the trade must be compared and reported, even though settlement between the parties may occur only as a movement on the books of the clearing broker. This is consistent with existing G–14 policy in TRS.

customer, but RTRS will add such a requirement.[21]

Another new feature added in the real-time environment is the Special Condition Code. RTRS will require a dealer that executes a trade with certain special conditions to code the trade report accordingly. For example, if there is a specific reason for a trade being reported at a price that is not a true market price, the dealer will indicate this with a Special Condition Code. A trade report with a Special Condition Code that is indicative of an off-market price will not be disseminated by RTRS, but will be made available to regulatory agencies for market surveillance and inspection purposes. Some Special Condition Codes will not be indicative of an off-market price but will report conditions such as a security that is traded "flat."[22]

RTRS will also add the reporting of a code by which a dealer will indicate that a price being reported was derived as part of a "weighted average price" transaction. A weighted average price transaction is one in which a dealer agrees to purchase up to a certain quantity of securities for a customer at market prices during the day, culminating with one sale transaction to the customer of the aggregate par value, with a price representing a weighted average of the dealer's purchases. The Price Dissemination Plan currently calls for displaying the "weighted average price" code along with other data about the transaction.

Another data element added for surveillance purposes is the identifier of an "intermediate dealer" in a transaction. This applies to a situation in which a dealer is a correspondent of an NSCC participant and this correspondent passes data to its clearing broker about a trade effected by a third dealer. Since the dealer that effected the trade is a correspondent of the clearing broker's correspondent, this dealer is termed the "correspondent's correspondent." The proposed reporting procedures would require that if there are three dealers on one side of an inter-dealer trade, all three dealers must be identified in the trade report: The clearing broker, its correspondent, and the correspondent's correspondent. (If there are only one or two dealers on a side, as will usually be the case, the new "correspondent's correspondent" field will be omitted.)

Finally, although it does not require any change in dealer procedures, RTRS will provide regulators with the record of all changes reported by a dealer after its initial trade submission. This is an enhancement over the current system, which reports the results of trade modifications but does not show the initial submission or the subsequent change records. RTRS will provide reports to regulators showing each modification or cancellation of a trade report, including the time the change was made. The MSRB plans also to provide regulators with real-time connections to RTRS. This will enable regulatory agency staff to obtain routine reports of transactions more quickly than is now possible.

RTRS Processing. Following is a description of key steps in RTRS processing with regard to input requirements, input data flow, format edits, submitter validation, timestamping, lateness checking, content validation, feedback, modification and cancellation, and the maintenance of the surveillance database.

• *Input Requirements.* The basic transaction information proposed to be reported by a dealer in RTRS will be similar to that reported in the existing transaction reporting system. This information supports both the price transparency and surveillance functions of the system. The complete list of data elements required on a trade report are in Specifications for Real-time Reporting of Municipal Securities Transactions[23] and will be included within the RTRS Users Manual, available at *www.msrb.org.*

• *Input data flow.* RTRS receives information about each trade separately as an electronic message and processes each trade individually.[24] All inter-dealer trade messages that contain initial values or modifications to data elements needed for comparison (*e.g.*, dollar price or par) come to RTRS as messages via RTTM or as input to the RTTM Web. Inter-dealer trade messages that affect only data elements needed for regulatory reporting (*e.g.*, time of trade) come to RTRS either as messages via the RTTM network, or as Web-based input via the RTTM Web or RTRS Web. Customer and IDRO messages, since they contain data needed exclusively for regulatory reporting, come to RTRS as messages via the RTTM network or as input to the RTRS Web (but not via the RTTM Web).

• *Format edits.* Each message will be edited to verify that its format is correct.[25] This involves checking that required data elements are present in the correct form (*e.g.*, dates are in date format and money amounts are in decimal format) and with the correct number of digits or characters. Messages that fail these edits will not be processed further and an error message describing the deficiency will be returned to the submitter. Both RTTM and RTRS will conduct format edits. Input from Web-based screens will have been checked before it is transferred from the user's personal computer to the Web server.

• *Submitter validation.* RTRS will accept input only from parties known to the MSRB. Trade messages routed through RTTM are checked by RTTM and rejected unless submitted to RTTM by an NSCC participant. The message is checked again when received by RTRS and is not processed further unless it bears the identifier of a clearing broker or service bureau known to the MSRB. RTRS further checks each trade message to verify that the dealer has previously authorized the submitter to report trades on its behalf. RTRS Web-based input is validated at multiple levels. First, the user cannot log on to RTRS unless he or she enters a user identifier and password issued by the MSRB. RTRS security controls allow a dealer access only to trades in which it was a party or which it has submitted on behalf of another dealer. Finally, the dealer-submitter combination is validated in the same way as input from RTTM, above.

• *Timestamping.* To enforce the rule on timely reporting of trades in the real-time environment, each trade message will be given an electronic timestamp, accurate to the second, when it is received. RTRS will interpret the timestamp as the time the trade was reported. Messages that are input through the Message Portal or the RTTM Web Portal will be timestamped by RTTM, and messages submitted via the RTRS Web Portal will be timestamped by the RTRS server. By this means, any delays that may occur in application processing or telecommunications connections between RTTM and the MSRB will not affect the assessment of the time the trade was reported.

[21] The dealer is not required to link the inter-dealer and customer transaction reports associated with agency transactions.

[22] The MSRB in its June 2003 Notice requesting comment on plans for real-time reporting (discussed below), referred to some of what are now termed Special Condition Codes as "Special Price Reason Codes."

[23] *See* "Revised Specifications for the Real-Time Transaction Reporting System, Version 1.2," MSRB Notice 2004–2 (January 23, 2004), on *www.msrb.org.*

[24] Screen input through either Web Portal is converted into message format by the appropriate Web server and sent from that server to the RTRS host computer.

[25] Message formats are defined in detail in the *Specifications for Real-time Reporting of Municipal Securities.*

• *Lateness checking.* The dealer will include an indicator in the trade message that shows the deadline that it understands applies to the trade report.[26] RTRS will determine whether the trade was received by the deadline. If the dealer indicates it has not traded the security in the previous year and therefore may report the trade up to three hours after the time of trade, RTRS will check whether the dealer's trading history is as claimed. If a trade is reported late, an error message indicating this fact will be sent to the submitter at the end of processing.

• *Content edits.* The values in the reported trade will be checked to determine that they are within reasonable limits, in order to detect input errors such as misplaced decimal points. The relationship between values is checked (*e.g.*, the settlement date may not precede the trade date) and crucial data elements are verified against reference tables (*e.g.*, the identifier of the dealer that effected the trade must be present in the RTRS dealer reference table). Finally, for those trades where the dollar price and yield are reported, the consistency of price and yield will be verified when possible.

• *Feedback.* If a dealer's message is deficient, RTRS interactive feedback will provide descriptive detail. MSRB anticipates that this feedback will help dealers to detect and correct errors quickly.

RTRS will generate an acknowledgement or error message for every reported trade, except inter-dealer trades that have passed RTTM edits and which do not have any RTRS errors. (These trades will already have been acknowledged by RTTM.) The acknowledgement/error message is sent to the dealer and/or submitter in the format(s) that the dealer or submitter has previously requested. The available feedback formats are message or e-mail. In addition, the dealer and the submitter may view the trade, and any errors found, using RTRS Web.

Feedback will indicate to the dealer whether the trade is error-free or late, and whether it is questionable or unsatisfactory for reporting purposes. A "questionable" trade message is one that appears to have an error, but which may be correct depending on circumstances. Examples are a trade with a yield that exceeds ten percent of the dollar price (bonds traded very close to a premium call may have a very high nominal yield, but this is most likely an input error) or a reported time of trade before 0600 hours (trading is allowed at any time of day, but this is most likely intended to be a time in the afternoon, *e.g.*, 5 p.m. reported as 0500). Under the proposed Rule G–14 RTRS Transaction Reporting Procedures, paragraph (e), dealers must examine such trade reports to determine if they are in fact erroneous and, if so, correct them. A trade is "unsatisfactory for reporting purposes" if it is missing an essential data element, is defective in some way that prevents it from being processed, or cannot be included in the surveillance database or publicly reported. Examples of "unsatisfactory" conditions are a reported trade date in the future, a missing dealer symbol, and an incorrect CUSIP check digit. Certain modification attempts are also unsatisfactory, such as a modification that cannot be matched with any previous message from the dealer.

• *Modification and cancellation.* Under the proposed rule change, the dealer is responsible for timely and accurate submission of trade reports. The dealer must monitor its reported trades by any of the available feedback methods and must correct any errors as soon as possible. If a dealer is unable to report a trade within the deadline, it must report the trade as soon as possible. RTRS will produce statistics on dealer performance in timely submission and timely correction of errors and will provide the statistics to dealers.

RTRS will enable dealers to submit, modify and cancel messages for all types of trades. Unlike the current transaction reporting system in which only customer trades can be modified to correct regulatory data, RTRS will support such changes for all trade types.

• *Surveillance database.* The RTRS Surveillance Database will store each message submitted by a dealer or service bureau. Audit trail reports will provide regulators with information about trades effected by a dealer, trades in specific CUSIPs, highest/lowest prices for a CUSIP within a day or other time period, and specific data elements such as trades with Special Condition Codes reported by a dealer. Other reports will show all modifications and cancellations reported by a dealer.

Testing and Contact Requirements. As described in connection with the proposed Rule G–14 Procedures, successful testing will be required of RTRS submitters to ensure a working interface with RTRS prior to the date for system operations. The proposed Procedures would require dealers to test their use of RTRS before reporting any trades. The MSRB will make testing facilities available to dealers at least six months before the announced effective date of the Proposed Rule Change ("Announced RTRS Start-Up Date"). Testing would be required of dealers making the transition from the current Transaction Reporting System to RTRS, and also required of dealers that begin reporting transactions in the future. Each dealer will have to be prepared to test its use of RTRS no later than three months before the Announced RTRS Start-Up Date and must schedule a test date by that time unless it has already successfully tested its RTRS capabilities. However, dealers that have effected an average of five or fewer transactions per week during the preceding year and that will use only the Web-based method must successfully test their RTRS capabilities one month before the Announced RTRS Start-Up Date.

The requirement for testing and submission of a new "Form RTRS" with the name of a contact person is reflected in the new proposed language for Rule G–14.

(iv) *Price Dissemination by RTRS. Description of Service.* Real-time price data will be available by subscription, after subscribers sign an agreement regarding re-dissemination. During the RTRS Business Day, price data will be disseminated in real time, immediately after receipt. Modifications and cancellations submitted by dealers that apply to earlier trade submissions will also be disseminated in real time.

The technical means of data dissemination are not yet determined. MSRB expects to make a second filing on the RTRS facility in the future with proposals for fees to be charged for the various RTRS data products.

In addition to real-time reports, the MSRB plans to continue providing reports each morning covering the previous day's trades (T+1 reports), as well as daily reports covering all trades done on the trading day one week earlier (T+5 reports), and monthly reports covering all trades done during the previous month.

Trades to be Disseminated. During the RTRS Business Day, the MSRB will disseminate data on all transactions as soon as they are received, except for two types of dealer submissions. The exceptions, which will be stored in the surveillance database but not disseminated in real-time, are trades marked as by the dealer as having prices other than market prices, using a

[26] As noted, trades must be reported within 15 minutes of the time of trade, except for new issue trades by syndicate managers or members at the list price (for which the deadline is the end of the first day of trading), trades in variable rate products or commercial paper (for which the deadline is the end of trade date), and trades in securities which the dealer has not traded in the previous year (for which the deadline is three hours from the time of trade).

Special Condition Code,[27] and reports of "inter-dealer regulatory-only" transactions. These have already been described.

List of Information Items to be Disseminated. The specific items proposed to be disseminated by RTRS for price transparency purposes are:

• CUSIP number and description of the issue traded;
• Par value of the transaction if one million dollars or under; otherwise reported as "1MM+";
• Dollar price;
• Yield (for inter-dealer new issue transactions done on a yield basis and for all customer transactions in non-defaulted securities where the transaction is done on a yield basis or if the yield can be computed from dollar price);
• Date and time of trade;
• Whether the transaction was a (i) purchase from a customer; (ii) sale to a customer; or (iii) inter-dealer transaction;
• Indicator that an inter-dealer transaction was done by a broker's broker and, if so, the broker's broker role as buyer or seller;
• When-issued indicator, if any;
• Syndicate list price indicator, if any;
• Assumed settlement date, if initial settlement date is not known at time of trade;
• Indicator that dollar price was computed by MSRB using an estimated settlement date for an issue on which the initial settlement date has not been set;
• Indicator that a trade was done at the weighted average price of trades done earlier in the day;
• Modification/Cancellation indicator, if any;
• RTRS broadcast time, date and sequential trade message number; and
• RTRS Control Number.

Transactions Done During RTRS Business Day. As noted, under the proposed rule language, dealers would with limited exceptions report within 15 minutes of the time of trade all transactions done during the RTRS Business Day. Trade submissions made during the RTRS Business Day will be disseminated within a few minutes of receipt.

Dissemination of Compared or Uncompared Inter-Dealer Trades. Unless the trade report contains errors or is subject to an exception, transactions reported by dealers during the RTRS Business Day would be disseminated within a few minutes after receipt at the designated RTRS Portal. The current plan for dissemination of prices calls for inter-dealer price information to be published only after comparison is achieved on the trade, as done in the current system. Comparison of the inter-dealer trade ensures the reliability of the data that was submitted, since the buyer's and the seller's details are matched. However, RTRS is being designed with the flexibility to disseminate uncompared inter-dealer transaction data if it is found that a substantial proportion of trades take longer than 15 minutes to be compared.[28]

Transactions Done Outside the RTRS Business Day. Under the proposed rule change, dealers would be required to report transactions done outside of the RTRS Business Day, but would not be required to do so on a real-time basis. Instead, trades would be reported within the first 15 minutes of the next RTRS Business Day, at which time they would be disseminated.

Late Trade Reports and Trade Data Modifications. Trades that are not reported within the timeframe set by the proposed rule change would be considered late. Late trade reports and trade modifications will be disseminated RTRS as soon as received if they are submitted during the RTRS Business Day and at the start of the next Business Day otherwise.

Broker's Broker Indicator. Trades by broker's brokers will be marked as such on disseminated trade reports and the buy/sell indicator will show whether the broker's broker was buying or selling. Because broker's broker trades occur in matched pairs that, in market terms, many observers view as representing one movement of securities between two dealers, the Board believes it will be helpful to RTRS data users if broker's brokers' trades are identified as such in trade reports.

(v) Implementation Schedule

RTRS development is proceeding on the following schedule.

2004

April—Beta testing with dealers began
July—Certification testing with dealers begins
July–Dec.—Dealers that have passed certification testing with RTTM and RTRS may report trades using new formats
October—Dealers that have not yet completed certification testing must schedule test, unless dealer reports an average of fewer than five trades per week (low-volume dealers)
November—Low-volume dealers that have not yet completed certification testing must schedule test
Dec. 15—All dealers must complete certification testing

2005

January—Real-time comparison and reporting requirements would become effective

2. Statutory Basis

The MSRB believes that the proposed rule change is consistent with section 15B(b)(2)(C) of the Act,[29] which provides that the Board's rules shall "* * * be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in municipal securities, to remove impediments to and perfect the mechanism of a free and open market in municipal securities, and, in general, to protect investors and the public interest * * *"[30] The MSRB believes that the proposed rule change is consistent with the Act in that it will provide the market with more efficient pricing information and will enhance investor confidence in the market.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Board does not believe that the proposed rule change will result in any burden on competition not necessary or appropriate in furtherance of the purposes of the Act, since it would apply equally to all dealers in municipal securities.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

(i) Introduction

Comments on the proposed rule change were solicited in a notice dated June 13, 2003 (the "June 2003 Notice").[31]

The MSRB received comments from:

[27] In an inter-dealer trade, if either dealer indicates the trade was done at a special price, RTRS considers the entire trade to be a special price trade.

[28] Unlike inter-dealer transactions, which have two submissions (both a buy side and a sell side) that must be compared, customer trades, which comprise approximately 80% of all reported trades, do not require comparison and will be disseminated as soon as automated error checks are completed.

[29] 15 U.S.C. 78o–4(b)(2)(C).

[30] *Id.*

[31] "Request for Comment: Plan for Real-Time Price Reporting," MSRB Notice 2003–23 (June 13, 2003), on *www.msrb.org.*

Alliance Capital Management Corporation ("Alliance Capital")[32]
The Asset Managers Forum ("AMF") of the Bond Market Association[33]
William Blair & Company LLC ("Blair")[34]
The Bond Market Association: Letter dated September 11, 2003 regarding operational issues ("BMA I")[35]
BMA: Letter dated September 12, 2003 regarding price dissemination ("BMA II")[36]
Cobey, Jacobson & Gordon, Inc. ("Cobey Jacobson")[37]
Financial Information Forum ("FIF")[38]
Fixed Income Securities, LLC (FIS)[39]
Griffin, Kubik, Stephens & Thompson, Inc. (5 e-mails) ("Griffin, Kubik")[40]
Hartfield, Titus & Donnelly, LLC ("Hartfield")[41]
Huntleigh Securities Corporation ("Huntleigh")[42]
Regional Municipal Operations Association ("RMOA")[43]
The Charles Schwab Corporation ("Schwab")[44]
Seattle-Northwest Securities Corporation ("Seattle-Northwest")[45]
Siebert Brandford Shank & Co., LLC ("Siebert")[46]
Southlake Capital, LLC ("Southlake")[47]
UBS Financial Services, Inc. ("UBS")[48]
The Vanguard Group ("Vanguard")[49]
Wachovia Bank, NA ("Wachovia")[50]
Wedbush Morgan Securities ("Wedbush")[51]

(ii) Comments on Real-Time Transparency

In the June Notice, the MSRB noted that it believes that real-time trade transparency will benefit the municipal securities market. The MSRB also noted that it had committed to reaching this goal. Commentators on the June Notice, however, are divided on whether transparency is generally beneficial to the market and on whether real-time transparency would harm the secondary market for certain infrequently traded issues. Two commentators believe that transparency generally benefits the municipal market and support the role of the MSRB in moving toward real-time price transparency. One commentator states that in general the MSRB proposal "would improve the transparency of the municipal securities markets and provide substantial benefits to the investing public." One commentator believes that real-time reporting will "enhance investor confidence in the municipal market" and that "while there will be short-term dislocations, eventually increased transparency will benefit all market participants." One commentator expresses the belief that the interests of mutual fund shareholders and individual bondholders "are surely best served with the highest degree of price transparency" and that "any short-term dislocations would be inconsequential compared to the long-term benefits offered by the MSRB's proposal."

Other commentators believe there is little increased benefit to greater transparency. They are concerned about negative liquidity effects, investor impacts and the possibility that dealers might exit the market if their spreads are narrowed. Three commentators believe that transparency will cause dealers to leave the market and therefore will adversely affect investors.

(iii) Comments on Operational Aspects

15-Minute Reporting Requirement. Four commentators express their concern about the operational resources necessary to achieve real-time reporting. One commentator "wholeheartedly supports the approach MSRB has taken in using RTTM for submission of transaction data to RTRS" and "commend[s] the MSRB for coordinating the move to RTRS to coincide with NSCC's transition to RTTM." However, four commentators state concerns about the cost of redesign to the industry that will be necessary for compliance with the 15-minute reporting requirement and the possibility that the operating costs for small firms may make them less competitive with large firms.

The MSRB has designed RTRS to minimize the redesign and operational costs to report trades in real-time. The implementation date of real-time transaction reporting, originally scheduled for 1997, has been delayed by the MSRB several times to give dealers additional time to make changes in bond processing systems necessary to capture trade data and process it on a real-time basis.[52] The current focus on straight-through processing of securities transactions provides the best possible environment to make the conversion to real-time transaction reporting.[53] In particular, the contemporaneous development of RTTM by NSCC will allow dealers to leverage their systems development work to satisfy two goals at once—that of real-time transaction reporting and real-time comparison of inter-dealer transactions. For trades that are not eligible for comparison, NSCC will not process the transaction data submitted, but will immediately forward the data to the MSRB. This will allow dealers to avoid setting up separate telecommunications links and facilities specifically for trade reporting these trades to the MSRB.

Schedule for Phase-In of Real-Time Reporting. Five commentators state their belief that there should be a phased-in approach to dealer testing and implementation of RTRS. One of these commentators states that dealers require a minimum of six months of testing of RTRS after RTTM is fully operational, and proposes that after six months of RTTM operation, dealers would begin

[32] Letter from R. B. Davidson, III and Fred S. Cohen, Alliance Capital, to Justin Pica, MSRB, dated August 27, 2003.

[33] Letter from Kenneth Juster, The Asset Managers Forum, to Harold L. Johnson, MSRB, dated September 15, 2003.

[34] Letter from James D. McKinney, William Blair and Co., to Harold L. Johnson, MSRB, dated September 14, 2003.

[35] Letter from Lynette Kelly Hotchkiss, The Bond Market Association, to Harold L. Johnson, MSRB, dated September 11, 2003.

[36] Letter from Lynette Kelly Hotchkiss, The Bond Market Association, to Harold L. Johnson, MSRB, dated September 12, 2003.

[37] Letter from H. Todd Cobey, Cobey, Jacobson & Gordon, Inc., to Christopher Taylor, MSRB, dated August 7, 2003.

[38] Letter from W. Leo McBlain and Thomas J. Jordan, Financial Information Forum, to Harold L. Johnson, MSRB, dated September 12, 2003.

[39] Letter from Jim Dillahunty, Fixed Income Securities, LLC, to John Baughman, MSRB, dated October 31, 2003.

[40] E-mails from Brian J. Battle, Jeff S. Kellough, Shane S. Kranov and Tom W. Boylen, Griffin, Kubik, Stephens & Thompson, Inc., to Justin Pica, MSRB, dated October 3, 2003.

[41] Letter from John J. Lynch, Jr., to Harold L. Johnson, MSRB, dated October 1, 2003.

[42] Letter from John A. Bohrmann and Catherine T. Marshall, Huntleigh Securities Corp., to Larry Lawrence, MSRB, dated September 24, 2003.

[43] Letter from Thomas Sargant, Regional Municipal Operations Association, to Harold L. Johnson, MSRB, dated September 25, 2003.

[44] Letter from Diana Kohanski, The Charles Schwab Corporation, to Justin Pica, MSRB, dated September 8, 2003.

[45] Letter from John Rose and Maud Daudon, Seattle-Northwest Securities Corp., to Harold L. Johnson, MSRB, dated October 13, 2003.

[46] Letter from Harold Durk, Siebert Brandford Shank & Co., LLC, to Harold L. Johnson, MSRB, dated September 12, 2003.

[47] Letter from Richard L. Sandow, Southlake Capital, LLC, to Harold L. Johnson, MSRB, dated June 13, 2003.

[48] Letter from Charles Paviolitis, UBS Financial Services, Inc., to Justin Pica, MSRB, dated August 29, 2003.

[49] Letter from John J. Brennan, The Vanguard Group, to Harold L. Johnson, MSRB, dated September 9, 2003.

[50] Letter from Donna M. D'Orazio, Wachovia Bank, NA, to Harold L. Johnson, MSRB, dated September 15, 2003.

[51] Letter from David Colville, Wedbush Morgan Securities, to Harold L. Johnson, MSRB, dated October 9, 2003.

[52] *See, e.g.,* "Real Time Reporting of Municipal Securities Transactions," *MSRB Reports*, Vol. 21, No. 2 (July 2001), and "Plans for MSRB's Real-Time Transaction Reporting System," MSRB Notice 2003–3 (February 3, 2003), on *www.msrb.org.*

[53] *See, e.g.,* "SIA Board Endorses Program to Modernize Clearing, Settlement Process for Securities," SIA Press Release (July 18, 2002) on *www.sia.com.*

submitting most inter-dealer trades through RTTM under the 15-minute reporting requirement. Two commentators would initiate reporting of customer trades using messages sent through RTTM at the same time as inter-dealer trades, but would delay subjecting customer trades to the 15-minute requirement until dealers have six months of experience with real-time inter-dealer trade reporting.

One commentator suggests that during the testing and phase-in period the MSRB provide "progress reports" that would help dealers measure their success and become aware of areas that need improvement. This commentator believes that regulators, in assessing individual firms' performance, should not use the progress reports. One commentator states that dealers "will need the co-operation of the enforcement agencies in recognizing the difference between non-compliance and growing pains."

The MSRB notes that in December 2003 it announced a revised schedule that extended the RTRS operational start date from mid-2004 to January 2005 and thereby provided six more calendar months for dealer system preparation. The MSRB believes this went far to allay the concerns expressed above relating to dealer readiness for real-time transaction reporting. Under the revised schedule, RTRS was available for beta testing with dealers in April 2004. In July 2004, RTRS will go into parallel operation with RTTM. Dealers will continue to be able to test with RTRS from this point onward, and, in addition, may at any time before January 2005 opt voluntarily to submit trades in the message format and to discontinue using the current batch format. Dealers voluntarily using the message format before 2005 will be encouraged to submit trade reports in real time, but the current end-of-day requirement will remain in effect until 2005.

Based on the above schedule, the MSRB is not aware of an operational reason to phase in the customer trade reporting requirement six months after the inter-dealer reporting requirement as requested by some commentators. Both customer and inter-dealer trades accordingly are proposed to become subject to the 15-minute requirement in January 2005.

With regard to the request for compliance progress reports, the MSRB plans during the testing period to make reports available to each dealer showing the dealer's performance on the various compliance parameters, along with industry averages for each parameter. To the extent that these reports will relate to dealer performance during the test period on 15-minute reporting (rather than the existing requirement to report by midnight of trade date), the MSRB notes that the performance data is not intended to relevant for enforcing existing "end-of-day" reporting requirements.

Exemption from the 15-Minute Requirement for Syndicate and Other New Issue Trades. Several commentators discuss the reporting of trades by an underwriting syndicate and other trades in new municipal securities issues. One commentator states that there are so many transactions associated with a new issue that it may be physically impossible to enter them all within 15 minutes. Two commentators note that CUSIP numbers and "indicative data" (securities descriptive data needed to make price/yield calculations and to confirm a transaction, such as dated date, coupon and maturity) are often not available to market participants, especially dealers that are not in an underwriting syndicate, on the first day of trading of new issues. Regarding syndicates, one commentator states that "the Syndicate Manager always has the complete details before the Selling Members, putting the Selling Members at a disadvantage."

In addition, five commentators question the value of reporting syndicate trades because, as one commentator states, "on sale date, the new issue transactions are done at a price that is already publicly known by way of the public offering itself," and therefore there is little need for real-time disclosure of these new issue prices. One commentator notes that the price reported on the first official day of trading in an issue may reflect an agreement based on market conditions on a day that precedes the initial trade date for the issue. This commentator further states that trade reports on the initial trade date for a new issue may consist of both primary market trades (possibly based on prices agreed to days before) and secondary market trades reflecting that day's market environment, which, it says, might mislead some investors as to prevailing market prices on the initial trade date.

Five commentators propose that reports of new issues should be required by the end of the first trading day or, if the CUSIP number is still not available, the next day. One commentator states that "this should be considered a temporary reprieve and the industry should begin to search for a more permanent solution." One commentator proposes a flag for trades in the primary or secondary market to indicate that a submission has exceeded the 15-minute window because the CUSIP had to be added to the firm's or to its vendor's security master file.

The MSRB agrees, in light of the large number of pre-sale commitments that a syndicate manager or syndicate member may have to report when a bond purchase agreement is signed or an award is announced, that it may be burdensome and even impossible in some cases for a syndicate manager or member to report all of these transactions within 15 minutes using systems that are currently available to dealers. Accordingly, the planned changes to Rules G–12(f) and G–14 will allow syndicate managers, syndicate members and selling group members to report their trades done at the list offering price as late as at the end of the day on which the issue was traded. They would be required to include in the trade report an indicator to show that the trade is a "syndicate price trade," *i.e.*, a trade done by a syndicate manager or member at the list offering price on the first day of trading. Once a new issue has been released for trading, normal transaction reporting rules will apply to the syndicate manager and members and they will be required to enter trades within 15 minutes of the time of trade, as they also will be required to do for trades done at other than the publicly stated list price.

With respect to the concern that syndicate prices are mixed in with "secondary market" prices on the initial trade date, the MSRB plans to disseminate the "syndicate list price" indicator with the trade as part of the transparency reports. The MSRB also will monitor this area to see if additional action is warranted. With respect to the concern that it is sometimes difficult for dealers to obtain issue information such as CUSIP numbers in order to submit trades within 15 minutes,[54] the MSRB is reviewing possible modifications to Rule G–34 on CUSIP numbers and new issue requirements to enhance the availability of this information and to ensure that trades are submitted in a timely manner after execution occurs in the new issue market.

The comments on adding new CUSIP numbers and indicative data for new issues are addressed in the next paragraph, since a similar topic arises in connection with some secondary market transactions.

Exemption for Trades in Issues Not Traded in the Prior Year. Six

[54] For a discussion of this concern, *see* "Real-Time Transaction Reporting: Revised Schedule and Operational Plan," MSRB Notice 2003–44 (December 11, 2003) on *www.msrb.org.*

commentators discuss secondary market trades of securities that have not been traded for a long time.[55] They state that it is not practical for a dealer to keep all 1.5 million CUSIP numbers in its securities master file in preparation for a possible trade, and that it is not possible to obtain and enter a CUSIP number and indicative data for such a security within 15 minutes of the trade. These commentators cite times ranging up to several hours as being necessary, depending on circumstances.[56] The same considerations would apply to a dealer that is not a member of a syndicate and that is trading a new issue for the first time.

The MSRB understands that, using existing systems, a dealer that does not currently have a CUSIP number in its security master file might reasonably take as much as three hours to enter the issue into its securities master, even when best efforts are applied. Therefore, the proposed rule change will provide, when a dealer has not traded an issue within the past year, that a three-hour trade reporting requirement will apply rather than a 15-minute reporting requirement. The dealer will be required to code the trade report with an indicator to show that the report was delayed because of the need to add the CUSIP number to the dealer's master file. Because the MSRB believes it is practical for a dealer's securities master file to hold all the CUSIP numbers it has traded in the previous year, a dealer will not be allowed to use this exemption for a particular CUSIP more than once during the year it is in operation. Trades that the dealer indicates are delayed because of the need to add the CUSIP number will be checked against the dealer's previous transaction reports to ensure that the issue had not been traded by that dealer during the past year. The three-hour requirement also would apply to new issue securities that a dealer trades for the first time, as long as the dealer in question is not the syndicate manager or a syndicate member. This should address concerns dealers have about obtaining new issue information on issues that they are not underwriting. The MSRB believes that syndicate managers and syndicate members do have, or should have, timely access to information on a new issue that they are underwriting.

The three-hour provision will expire or "sunset" automatically after one year from the date of RTRS implementation. During this year, MSRB plans to work with dealers, trade associations and information vendors to ensure that industry efforts are being made to speed up the process of updating securities master files and that indicative data provided by the various commercial services meets dealer needs with respect to 15-minute transaction reporting with respect to quality and consistency as well as speed.

Exemption for Variable and Short-Term Instruments. Two commentators note that short-term instruments such as variable rate demand obligations (VRDOs), commercial paper and auction rate instruments typically are traded at par or at the clearing bid rate, and three commentators state that there is limited benefit to disseminating such prices in real time. Two commentators cite the difficulty of real-time reporting of transactions in these instruments, since they are sold at auction with unpredictable results and are large issues involving numerous investors. They believe that trades in short-term instruments should be reported at the end of the day rather than within 15 minutes. However, one commentator states that VRDO reporting should be reported in real time because "it is preferable to have a consistent procedure for submitting these trades."

The MSRB understands that trades in variable rate products (including auction rate products) and commercial paper frequently are processed in a different manner than other fixed rate municipal securities. Because it may present significant operational challenges for dealers to incorporate these instruments in the 15-minute reporting stream, the proposed rule change would require that trades in short-term instruments, including variable rate and auction rate products and commercial paper, be reported by the end of the day rather than within 15 minutes. The dealer will include an indicator in the trade report to show that the security is being reported outside the 15-minute window for this reason. The proposed rule change would require that trades in longer-term notes (*i.e.*, securities with a fixed or zero interest rate and over nine months in maturity) be subject to normal reporting rules.

The MSRB does not currently plan to require reports of yields or reset rates on variable rate and auction rate products, but continues to be interested in price transparency in this area. Accordingly, the MSRB will explore other ways to provide transparency for the short-term rates that are being set in reofferings and in variable rate and auction products.

Discrepancies in Timestamps on Inter-Dealer Trades. The BMA states that its members "question the basis upon which the valid timestamp [on a trade report] will be determined in the case of an inter-dealer discrepancy," and it asks the MSRB to clarify this point. RTRS processing will assume that if there are different times on sides of an inter-dealer trade, the earlier time is correct. If the times differ by more than 15 minutes, RTRS will send messages to parties on both sides informing them of the difference, but RTRS will not mark either time as invalid. The MSRB plans to review this assumption as experience is gained with real-time reporting.

ATS Indicator. The June 2003 notice requested comments about designating certain trades that are done through alternative trading systems (ATSs). The BMA states that the expectation that ATS trades will be reported is "both problematic and unnecessary" and asks for additional information from the MSRB about the utility of reporting and disseminating the ATS designation. This commentator states that trading information through ATSs is already reported to the SEC and that the SEC might make such information available to the MSRB.[57] Hartfield states that, while it is registered as an ATS, it does not execute trades with broker-dealers through electronic means, but instead functions as a voice-broker. In light of this, the commentator believes "the identification of our trades as ATS trades will be confusing, and provide inaccurate data."

The commentators have raised issues that would be problematic for real-time reporting in the case of an ATS dealer in municipal securities that also does non-ATS trades. The MSRB plans to review the issue to determine whether there is another way to enhance existing audit trail capabilities with respect to electronically executed trades without identifying traditional voice brokered trades as "ATS" transactions. At this time, the MSRB is dropping the requirement for dealers to identify ATS trades, but is retaining the field in the reporting format for potential use later.

[55] One commentator states the problem is exacerbated for West Coast firms that use East Coast clearing firms and that trade late in the afternoon Pacific Time.

[56] One commentator states that up to two hours are necessary and another states that setup can take more than three hours. One commentator states that "this process is normally measured in hours, not minutes." One commentator depends upon a service bureau where setting up a CUSIP "can take quite a bit of time." One commentator, without citing details, states a concern about the time to set up non-investment grade paper. One commentator states that even dealers that have integrated data services with their processing systems still take approximately 7–11 minutes to set up a security traded in the secondary market, if it was not already set up.

[57] The MSRB understands that the SEC does not have trade-level data on ATS trades similar to the RTRS trade-level data. ATSs send quarterly summaries of activity to the SEC but they do not report to the SEC each transaction price and size.

When RTRS is initially implemented, dealers will not be required to populate the ATS indicator in trade reports.

RTRS Business Day. The June 2003 Notice requested comment on the proposed requirement to report trades within 15 minutes if the trades are done during the "RTRS Business Day," defined as the period between 7:30 a.m. and 6:30 p.m. Eastern time. The time of receipt of an electronic trade report would be the time of its arrival at NSCC. Trades reported during the Business Day would be disseminated in real-time. Transactions effected outside of the RTRS Business Day would have to be reported by dealers no later than 15 minutes after the start of the next RTRS Business Day. Schwab states that it "prefer[s] to follow the same procedures used in GSCC reporting" but does not specify the GSCC procedures or their advantages. Hartfield agrees with the MSRB's proposal that the RTRS business day would be defined to extend from 7:30 a.m. to 6:30 p.m. The proposed rule change retains the definition of the RTRS Business Day contained in the June 2003 Notice.

(iv) Comments on Trades To Be Disseminated

Divided Views on Infrequently Traded Issues. Some commentators that generally support transparency nevertheless express concern about its effect on liquidity in certain market segments. The BMA describes its concern as being focused on issues that are "concentrated in the hands of a few dealers or buy-side institutions" which are traded "when a bond has been outstanding for a considerable period of time or has a low or uncertain credit standing".[58] The BMA also suggests that an economic study should be conducted to examine the issue. The BMA states,

> * * * Immediate price dissemination for bonds that are infrequently traded and difficult to trade will likely mean that dealers will either be less willing to supply liquidity to the market by buying bonds in these circumstances, or else will only buy them at a discounted price that accounts for this additional risk.* * * [59]

The opposite view is expressed by Vanguard, which proposes that all trades should be disseminated. Vanguard believes that the goals of real-time price transparency should apply to "actively traded securities and, especially, inactively traded ones." It states, "we strongly oppose * * * the exclusion of inactively traded securities from the reporting regime."

Proposals to Phase-In Real-Time Price Dissemination. Several commentators suggested that a phased implementation, in which some issues are held back from real-time dissemination in the initial phase, might ease liquidity concerns. Seattle Northwest, without proposing details, states that dissemination should be phased-in "in order to further study the impact on liquidity of infrequently traded bonds." The BMA [60] proposes that the MSRB immediately disseminate trades in all bonds rated "A" or higher and all trades of $1 million or less, regardless of rating. Under this proposal, trades in bonds rated below "A" that are over $1 million in size would not be disseminated in real-time.[61] Alliance Capital, which also stated that it would like "more disclosure of trading in blocks greater than $1 million," proposes deferring dissemination of trades in bonds rated below "AA –" and phasing in the remainder of trades.

In considering the comments on phasing in real-time transparency, the MSRB weighed the potential for liquidity problems against the potential for transparency benefits. The MSRB believes that any liquidity problems that may occur are likely to be temporary and will resolve over time as market participants make adjustments in response to the more transparent environment. The MSRB also believes that the potential for transparency benefits, such as more accurate pricing, lower transaction costs for investors and increased investor confidence, outweighs the potential for short-term liquidity problems. On this basis, the MSRB has determined that, with the exception of issues that are not required to be reported by dealers within 15 minutes of the trade, all transactions should be disseminated in real-time as they are executed.

(v) Comments on Information To Be Disseminated

Display of Par Value. The current TRS system produces reports that display actual par value on all transactions of $1 million or less that were effected the previous day and an indicator for larger trades stating only that the trade size was over $1 million. The "par value screen" for trades over $1 million was adopted by the MSRB in 2002 because of concerns that the exact par value of large trades tends to identify the market participants involved in those trades in thinly traded issues.[62] In connection with its phase-in proposal, the BMA suggests that real-time trade reports disclose par value of transactions in investment-grade securities, showing actual trade size for trades up to $5 million in par value, with actual par value shown for the remaining trades on a report made one week later, as is done today. Alliance Capital also states that more information on par value should be shown on trade reports. Wachovia "strongly agree[s]" with the MSRB's current policy of displaying "1MM+" for all trades of $1 million or more to prevent easy identification of the trading parties.

Because the primary purpose of real-time transparency is to provide price information, and because the concern over identifying parties to transactions in real-time with exact par values of large trades, the MSRB at this time is proposing to retain the policy of displaying the exact par value for trades of $1 million or less and displaying "1MM+" for larger trades. The same values will be displayed on reports published each morning covering the previous day's trades (T+1 reports). As currently, exact par values of all trades will be disseminated five business days after trade date. The MSRB will review this policy as it gains experience with real-time transparency.

Broker's Broker's Transactions. The June 2003 Notice asked whether RTRS trade reporting could in some way address concerns that have been expressed about the reporting of broker's broker's trades in the same way as other inter-dealer trades. It can be argued that this format "double counts" this movement of securities between dealers since many observers consider the broker's broker's two trades effectively to be only one "trade" in the market. Hartfield, a broker's broker, comments that MSRB should not disseminate broker's broker's trades at all because "these trades do not accurately reflect the information intended by price transparency, *i.e.*, PRICE information. * * *" UBS [at 3] believes "identifiers used to indicate * * * broker's broker trades * * *.will help avoid double counting. * * *" RMOA states that these trades should be reported because "including them would not exaggerate volume but would clearly reflect the path the bond has taken."

[58] *See* note 36 *supra*, at 4.

[59] *Id.*

[60] The Asset Managers Forum, which describes itself as an independent affiliate of the BMA, agrees with the BMA proposals.

[61] Trades in all bonds will be disseminated one week after trade date, as they are now. No commentators oppose this feature.

[62] TRS publishes a comprehensive transparency report one week after trade date, which includes dealer error corrections and late trade reports. This report shows the actual par value for trades over $1 million.

The MSRB has determined to disseminate broker's brokers' trades along with an indicator that they were effected by a broker's broker, and to indicate whether the broker's broker bought or sold the security. As noted above, broker's broker trades occur in matched pairs that, in market terms, many observers view as representing one movement of securities between two dealers. Accordingly, the Board believes it will be helpful to RTRS data users if broker's broker's trades are identified as such in trade reports.

Agency and Riskless Principal Transactions. As with broker's brokers' trades, users of TRS data sometimes have been confused over reports of agency transactions by dealers. In TRS, and as planned in RTRS, the dealer reports both sides of an agency transaction and these trade reports are each disseminated, even though many observers consider it to be one trade. In response to the June 2003 Notice, one commentator, UBS, suggested that agency and riskless principal indicators be disseminated in trade records to avoid the double counting issue inherent in these situations.

Although new capabilities in RTRS would allow the system to identify agency trades on disseminated reports of inter-dealer trades, RTRS will have no capability to identify riskless principal trades. Indicating agency trades without similarly marking riskless principal transactions would introduce inconsistent treatment of two types of transactions that most observers consider to be equivalent in economic terms. Therefore, RTRS will not disseminate agency or riskless principal indicators in its transparency reports.

Inter-Dealer Regulatory-Only Reports. Another double counting issue concerns the new type of trade report in RTRS termed the Inter-Dealer Regulatory-Only or "IDRO" report (described above). The MSRB has determined not to disseminate IDRO reports as trades. The IDRO is reported to the MSRB for audit trail purposes and is substantially different than a true, principal-to-principal, trade between dealers. Each IDRO is related to a separately reported and disclosed transaction with a customer. Given the existence of the reported customer trade showing the net price paid by the customer, the IDRO imparts no additional market pricing information.

Trades Reported at Prices Other than the Market Price. The June 2003 Notice asked whether codes showing that a trade was done at a price different than the true market price should be disseminated or whether off-market trades should be disseminated at all. It also asked dealers to describe specific reasons that might cause a transaction to be effected at an off-market price. RMOA gives as an example of a special price a premium price paid to cover a Depository Trust Corporation short position.

Under current practices, trades done at a price different than the market price are not separately indicated by dealers reporting trades to TRS. When such trade reports are received, they are disseminated and contribute to intra-day price discrepancies seen in the current T+1 reports. Therefore, the MSRB has determined not to disseminate trades that the dealer indicates as trades done at other than the market price. (Certain Special Condition Codes will be indicative of prices other than the market price.[63]) All special price trades nevertheless will be kept in the RTRS database for surveillance purposes for use by the NASD, SEC and bank regulatory agencies. RTRS will, however, disseminate "weighted average" trades that are received, with an indicator to that effect.

Transaction Control Numbers. RTRS will assign a "control number" to each transaction reported by a dealer. This is a unique number that will apply to the initial submission and subsequent corrections or cancellations of trade data.[64] The June 2003 Notice asked for views on the use of the RTRS control number to track trade report corrections and modifications. The intent was to obtain comment both on the operational question of dealers using the control number to refer to a submission when making a change, and on the question of disseminating the control number so that a user of public trade information can tell when a trade has been changed after it is first disclosed. In response, Schwab, RMOA and UBS state that they agree with the MSRB's proposed use of the control number on trade information disseminated by RTRS.

The MSRB plans to disseminate trade corrections and modifications in real time, including the RTRS control number on original trades and on any subsequent changes in the trade. This will enable users of real-time information to more easily update their databases when dealers make changes to trades that have been reported and disseminated.

[63] As previously noted, the June 2003 Notice used the term "Special Price Reason Code" to refer to some of what are currently called Special Condition Codes.

[64] In making trade corrections, a dealer may refer to a transaction using either the RTRS control number or its own control number.

Comment on National Matrix. Blair states that instead of increasing transparency, a national matrix should be established that would provide investors with yield information via the MSRB's Web site and the Wall Street Journal. The MSRB notes that private vendors publish matrix-type information in the form of various daily scales, and believes it would add little benefit for the MSRB to publish a matrix.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 35 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

A. By order approve such proposed rule change, or

B. Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to *rule-comments@sec.gov*. Please include File Number SR–MSRB–2004–02 on the subject line.

Paper Comments

• Send paper comments in triplicate to Jonathan G. Katz, Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609.

All submissions should refer to File Number SR–MSRB–2004–02. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the Board's principal offices. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–MSRB–2004–02 and should be submitted on or before July 20, 2004.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[65]

Jill M. Peterson,

Assistant Secretary.

[FR Doc. 04–14676 Filed 6–28–04; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49903; File No. SR–NASD–2004–086]

Self-Regulatory Organizations; Notice of Filing and Immediate Effectiveness of Proposed Rule Change and Amendment No. 1 Thereto by the National Association of Securities Dealers, Inc. to NASD Rule 4200 to Clarify the Treatment of Certain Non-Preferential, Ordinary-Course Payments

June 22, 2004.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act")[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on June 1, 2004, the National Association of Securities Dealers, Inc. ("NASD"), through its subsidiary, the Nasdaq Stock Market, Inc. ("Nasdaq"), filed with the Securities and Exchange Commission ("Commission") the proposed rule change as described in items I, II, and III below, which Items have been prepared by Nasdaq. On June 17, 2004, Nasdaq submitted Amendment No. 1 to the proposed rule change.[3] The proposed rule change has been filed by Nasdaq as a "non-controversial" rule change under Rule 19b–4 under the Act,[4] which renders the proposal effective upon filing with the Commission.[5] The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

Nasdaq proposes to change Rule 4200(a)(15) to clarify the treatment of certain non-preferential payments made by financial institutions to directors of listed companies and their family members in the ordinary course of business. The text of the proposed rule change is below. Proposed new language is in *italics*; proposed deletions are in brackets.[6]

* * * * *

Rule 4200. Definitions

(a) For purposes of the Rule 4000 Series, unless the context requires otherwise:

(1)–(14) No change

(15) "Independent director" means a person other than an officer or employee of the company or its subsidiaries or any other individual having a relationship, which, in the opinion of the company's board of directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. The following persons shall not be considered independent:

(A) No change

(B) a director who accepted or who has a Family Member who accepted any payments from the company or any parent or subsidiary of the company in excess of $60,000 during any period of twelve consecutive months within the three years preceding the determination of independence, other than the following:

(i)–(iii) No change

(iv) benefits under a tax-qualified retirement plan, or non-discretionary compensation; [or]

(v) loans from a financial institution provided that the loans (1) were made in the ordinary course of business, (2) were made on substantially the same terms, including interest rates and collateral, as those prevailing at the time for comparable transactions with the general public, (3) did not involve more than a normal degree of risk or other unfavorable factors, and (4) were not otherwise subject to the specific disclosure requirements of SEC Regulation S–K, Item 404;

(vi) payments from a financial institution in connection with the deposit of funds or the financial institution acting in an agency capacity, provided such payments were (1) made in the ordinary course of business; (2) made on substantially the same terms as those prevailing at the time for comparable transactions with the general public; and (3) not otherwise subject to the disclosure requirements of SEC Regulation S–K, Item 404; or

(vii) loans permitted under Section 13(k) of the Act.

Provided however, that in addition to the requirements contained in this paragraph (B), audit committee members are also subject to additional, more stringent requirements under Rule 4350(d).

(C)–(G) No change

(16)–(38) No change

(b) No change

IM—4200 Definition of Independence—Rule 4200(a)(15)

It is important for investors to have confidence that individuals serving as independent directors do not have a relationship with the listed company that would impair their independence. The board has a responsibility to make an affirmative determination that no such relationships exist through the application of Rule 4200. Rule 4200 also provides a list of certain relationships that preclude a board finding of independence. These objective measures provide transparency to investors and companies, facilitate uniform application of the rules, and ease administration. Because Nasdaq does not believe that ownership of company stock by itself would preclude a board finding of independence, it is not included in the aforementioned objective factors. It should be noted that there are additional, more stringent requirements that apply to directors serving on audit committees, as specified in Rule 4350.

The Rule's reference to a "parent or subsidiary" is intended to cover entities the issuer controls and consolidates with the issuer's financial statements as filed with the Commission (but not if the issuer reflects such entity solely as an investment in its financial statements). The reference to executive

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[65] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* letter from Edward S. Knight, Executive Vice President, Nasdaq, to Katherine A. England, Assistant Director, Division of Market Regulation ("Division"), Commission, dated June 16, 2004 ("Amendment No. 1"). Amendment No. 1 clarified the text of IM–4200 regarding the three-year "look back" periods applicable to certain provisions of the definition of "independent director" in NASD Rule 4200. The change conforms with a recent amendment to the text made by Nasdaq in another proposal. *See infra* note.

[4] 17 CFR 240.19b–4.

[5] 17 CFR 240.19b–4(f)(6).

[6] Changes are marked based on the text of Rule 4200 as amended by File No. SR–NASD–2004–80 and Amendment No. 1 thereto.

officer means those officers covered in Rule 16a–1(f) under the Act. In the context of the definition of Family Member under Rule 4200(a)(14), the reference to marriage is intended to capture relationships specified in the Rule (parents, children and siblings) that arise as a result of marriage, such as "in-law" relationships.

The three year look-back periods referenced in paragraphs (A), (C), (E) and (F) of the Rule commence on the date the relationship ceases. For example, a director employed by the company is not independent until three years after such employment terminates.

Paragraph (B) of the Rule is generally intended to capture situations where a payment is made directly to (or for the benefit of) the director or a Family Member of the director. For example, consulting or personal service contracts with a director or Family Member of the director or political contributions to the campaign of a director or a Family Member of the director would be considered under paragraph (B) of the Rule. *Subparagraph (v) clarifies that a loan from a financial institution that was exempt from specific disclosure pursuant to Instruction 3 to SEC Regulation S–K, Item 404(c) will not preclude a finding of director independence. Subparagraph (vi) clarifies that certain payments from financial institutions will not preclude a finding of director independence. In particular, subparagraph (vi) is intended to capture standard, non-preferential payments made by financial institutions in the ordinary course of business such as interest payments made by a bank on deposits, certificates of deposits, or savings bonds. Furthermore, subparagraph (vi) is intended to capture technical "payments" made by a financial institution to its customers when the financial institution acts as an agent for its customers. For example, when a brokerage firm receives dividends for securities held by a customer, it will make a "payment" of the dividend amount to that customer. Likewise, when a brokerage firm executes a customer's order to sell the customer's securities, it will make a "payment" of the proceeds to the customer. Subparagraph (vi) clarifies that agency payments, such as those described above, shall not preclude a finding of director independence.*

Paragraph (D) of the Rule is generally intended to capture payments to an entity with which the director or Family Member of the director is affiliated by serving as a partner, controlling shareholder or executive officer of such entity. Under exceptional circumstances, such as where a director has direct, significant business holdings, it may be appropriate to apply the corporate measurements in paragraph (D), rather than the individual measurements of paragraph (B). Issuers should contact Nasdaq if they wish to apply the Rule in this manner. The reference to a partner in paragraph (D) is not intended to include limited partners. It should be noted that the independence requirements of paragraph (D) of the Rule are broader than Rule 10A–3(e)(8) under the Act.

Under paragraph (D), a director who is, or who has a Family Member who is, an executive officer of a charitable organization may not be considered independent if the company makes payments to the charity in excess of the greater of 5% of the charity's revenues or $200,000. However, Nasdaq encourages companies to consider other situations where a director or their Family Member and the company each have a relationship with the same charity when assessing director independence.

For purposes of determining whether a lawyer is eligible to serve on an audit committee, Rule 10A–3 under the Act generally provides that any partner in a law firm that receives payments from the issuer is ineligible to serve on that issuer's audit committee. In determining whether a director may be considered independent for purposes other than the audit committee, payments to a law firm would generally be considered under Rule 4200(a)(15)(D), which looks to whether the payment exceeds the greater of 5% of the recipient's gross revenues or $200,000; however, if the firm is a sole proprietorship, Rule 4200(a)(15)(B), which looks to whether the payment exceeds $60,000, applies.

Paragraph (G) of the Rule provides a different measurement for independence for investment companies in order to harmonize with the Investment Company Act of 1940. In particular, in lieu of paragraphs (A)–(F), a director who is an "interested person" of the company as defined in Section 2(a)(19) of the Investment Company Act of 1940, other than in his or her capacity as a member of the board of directors or any board committee, shall not be considered independent.

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II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, Nasdaq included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in item IV below. Nasdaq has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

NASD Rule 4200(a)(15)(B) generally provides that a director of a listed company will not be considered independent if that director or a family member accepted any payments from the company in excess of $60,000 per year in a three-year period. According to Nasdaq, the purpose of this proposed rule change is to clarify that certain standard, non-preferential transactions by financial institutions that technically involve "payments" by the financial institution to the financial institutions' customers will not preclude a finding of independence under this rule.

Nasdaq states that the ordinary business services provided by financial institutions, such as banks, often involve "payments" to the financial institutions' customers. For example, a bank customer technically receives "payments" from the bank in the form of interest payments on deposits, the receipt of a loan check, or the principal and interest from a matured savings bonds. A financial institution also may make agency "payments" to its customers in connection with securities transactions. For example, when a brokerage firm's customer receives dividends, the brokerage firm may receive the dividend from the issuer as the customer's agent, and then make a "payment" to the customer after it has received the dividend from the issuer. Furthermore, when a brokerage firm customer sells securities, the proceeds from the sale are first received by the brokerage firm since the securities are normally held in its name. Upon receipt of the proceeds from the sale, the brokerage firm will make a "payment" in the amount of the proceeds to the customer.

Nasdaq believes that these non-preferential and ordinary-course "payments" do not raise independence concerns and, therefore, should not preclude a finding of director independence. Any type of preferential or compensatory payment to a director or Family Member of a director in excess of $60,000 would continue to be considered pursuant to that Rule.

2. Statutory Basis

Nasdaq believes that the proposed rule change is consistent with the provisions of section 15A of the Act,[7] in general, and with section 15A(b)(6) of the Act,[8] in particular, in that it is designed to foster cooperation and coordination with persons engaged in regulating and processing information with respect to, and facilitating transactions in securities, to remove impediments to a free and open market and a national market system, and, in general, to protect investors and the public interest. In particular, the proposed rule change will benefit investors, issuers, issuers' counsel, and member firms by providing additional transparency to Nasdaq's corporate governance standards.

B. Self-Regulatory Organization's Statement on Burden on Competition

Nasdaq does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The proposed rule change has been designated by Nasdaq as a "non-controversial" rule change pursuant to section 19(b)(3)(A) of the Act[9] and subparagraph (f)(6) of Rule 19b–4 thereunder.[10]

The foregoing proposed rule change: (1) does not significantly affect the protection of investors or the public interest, (2) does not impose any significant burden on competition, and (3) by its terms does not become operative for 30 days after the date of this filing, or such shorter time as the Commission may designate, if consistent with the protection of investors and the public interest. Furthermore, the NASD gave the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change. Consequently, the proposed rule change has become effective pursuant to section 19(b)(3)(A) of the Act[11] and Rule 19b–4(f)(6) thereunder.[12]

Pursuant to Rule 19b–4(f)(6)(iii),[13] a proposed "non-controversial" rule change does not become operative for 30 days after the date of filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. Nasdaq has requested that the Commission waive the 30-day operative delay, to permit the NASD to implement the proposal immediately.

The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest. The Commission believes that the proposed rule change is a reasonable clarification of the rules regarding director independence, and that acceleration of the operative date should facilitate the application of those rules for listed companies. Therefore, the Commission designates the proposed rule change to be operative immediately.[14]

At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.[15]

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

• Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or

• Send an e-mail to *rule-comments@sec.gov*. Please include File No. SR–NASD–2004–086 on the subject line.

Paper Comments

• Send paper comments in triplicate to Jonathan G. Katz, Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609.

All submissions should refer to File No. SR–NASD–2004–086. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Section, 450 Fifth Street, NW., Washington, DC 20549. Copies of such filing also will be available for inspection and copying at the principal office of the NASD. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File No. SR–NASD–2004–086 and should be submitted on or before July 20, 2004.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[16]

Margaret H. McFarland,

Deputy Secretary.

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[7] 15 U.S.C. 78o–3.

[8] 15 U.S.C. 78o–3(b)(6).

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(6).

[11] 15 U.S.C. 78s(b)(3)(A).

[12] 17 CFR 240.19b–4(f)(6).

[13] 17 CFR 240.19b–4(f)(6)(iii).

[14] For the purposes only of accelerating the operative date of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[15] For purposes of calculating the 60-day abrogation period, the Commission considers the period to commence on June 17, 2004, the date that Nasdaq filed Amendment No. 1.

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–49901; File No. SR–NASD–2004–080]

Self-Regulatory Organizations; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change and Amendment No. 1 Thereto by the National Association of Securities Dealers, Inc. To Conform Certain Provisions of NASD Rules 4200 and 4350 to the Rules of Another Self-Regulatory Organization, and to Make Additional Revisions

June 22, 2004.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on May 18, 2004, the National Association of Securities Dealers, Inc. ("NASD"), through its subsidiary, the Nasdaq Stock Market, Inc. ("Nasdaq"), filed with the Securities and Exchange Commission ("Commission") the proposed rule change as described in items I, II, and III below, which items have been prepared by Nasdaq. On June 17, 2004, Nasdaq submitted an amendment to the proposed rule change.[3] Nasdaq has designated the proposed rule change as constituting a "non-controversial" rule change under subparagraph (f)(6) of Rule 19b–4 under the Act,[4] which renders the proposal effective upon filing with the Commission. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of the Substance of the Proposed Rule Change

Nasdaq proposes to amend NASD Rules 4200 and 4350 as set forth below. Proposed new language is in *italics*; proposed deletions are in brackets.[5]

* * * * *

Rule 4200. Definitions

(a) For purposes of the Rule 4000 Series, unless the context requires otherwise:

(1)–(14) No change

(15) "Independent director" means a person other than an officer or employee of the company or its subsidiaries or any other individual having a relationship, which, in the opinion of the company's board of directors, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. The following persons shall not be considered independent:

(A) No change

(B) A director who accepted or who has a Family Member who accepted any payments from the company or any parent or subsidiary of the company in excess of $60,000 during *any period of twelve consecutive months within the three years preceding the determination of independence* [the current or any of the past three fiscal years], other than the following:

(i)–(iv) No change

(v) loans permitted under Section 13(k) of the Act. Provided however, that *in addition to the requirements contained in this paragraph (B)*, audit committee members are *also* subject to additional, more stringent requirements under Rule 4350(d).

(C)–(F) No change

(G) In the case of an investment company, in lieu of paragraphs (A)–(F), a director who is an "interested person" of the company as defined in *S*[s]ection 2(a)(19) of the Investment Company Act of 1940, other than in his or her capacity as a member of the board of directors or any board committee.

(16)–(38) No change

(b) No change

IM—4200 Definition of Independence—Rule 4200(a)(15)

It is important for investors to have confidence that individuals serving as independent directors do not have a relationship with the listed company that would impair their independence. The board has a responsibility to make an affirmative determination that no such relationships exist through the application of Rule 4200. Rule 4200 also provides a list of certain relationships that preclude a board finding of independence. These objective measures provide transparency to investors and companies, facilitate uniform application of the rules, and ease administration. Because Nasdaq does not believe that ownership of company stock by itself would preclude a board finding of independence, it is not included in the aforementioned objective factors. It should be noted that there are additional, more stringent requirements that apply to directors serving on audit committees, as specified in Rule 4350.

The *R*[r]ule's reference to a "parent or subsidiary" is intended to cover entities the issuer controls and consolidates with the issuer's financial statements as filed with the [U.S. Securities and Exchange] Commission (but not if the issuer reflects such entity solely as an investment in its financial statements). The reference to executive officer means those officers covered in *SEC* Rule 16a–1(f) under the Act. In the context of the definition of Family Member under Rule 4200(a)(14), the reference to marriage is intended to capture relationships specified in the *R*[r]ule (parents, children and siblings) that arise as a result of marriage, such as "in-law" relationships.

The three year look-back periods referenced in paragraphs (A), (C), (E) and (F) of the Rule commence on the date the relationship ceases. For example, a director employed by the company is not independent until three years after such employment terminates.

Paragraph (B) of the *R*[r]ule is generally intended to capture situations where a payment is made directly to (or for the benefit of) the director or a [f]*F*amily [m]*M*ember of the director. For example, consulting or personal service contracts with a director or [f]*F*amily [m]*M*ember of the director or political contributions to the campaign of a director or a [f]*F*amily [m]*M*ember of the director would be considered under paragraph (B) of the *R*[r]ule.

Paragraph (D) of the [r]*R*ule is generally intended to capture payments to an entity with which the director or Family Member of the director is affiliated by serving as a partner, controlling shareholder or executive officer of such entity. Under exceptional circumstances, such as where a director has direct, significant business holdings, it may be appropriate to apply the corporate measurements in paragraph (D), rather than the individual measurements of paragraph (B). Issuers should contact Nasdaq if they wish to apply the *R*[r]ule in this manner. The reference to a partner in paragraph (D) is not intended to include limited partners. It should be noted that the independence requirements of paragraph (D) of the *R*[r]ule are broader

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[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* letter from Edward S. Knight, Executive Vice President, Nasdaq, to Katherine A. England, Assistant Director, Division of Market Regulation, Commission, dated June 16, 2004 ("Amendment No. 1"). In Amendment No. 1, Nasdaq clarified, in the text of its proposed rule language, a reference to exemptions that are not afforded to investment companies and deleted a proposed reference to NASD Rule 4200(a)(15) in the paragraph in the Interpretive Material to Rule 4200 relating to look-back provisions.

[4] 17 CFR 240.19b– 4(f)(6).

[5] Changes are marked from the text of NASD Rules 4200 and 4350 and IM–4200, which are currently available in electronic format in the NASD Manual at *http://www.nasd.com and http://www.nasdaq.com*. The relevant portion of current NASD Rule 4200 was approved in Securities Exchange Act Release No. 48745 (November 4, 2003), 68 FR 64154 (November 12, 2003). Changes with respect to NASD Rule 4350 are marked based on the rule text as amended by SR–NASD–2004–069. *See* Securities Exchange Act Release 49732 (May 19, 2004), 69 FR 29774 (May 25, 2004). Nasdaq represents that no other pending or approved rule filings would affect the text of these Rules.

than *SEC* Rule 10A–3(e)(8) under the Act.

Under paragraph (D), a director who is, or who has a Family Member who is, an executive officer of a charitable organization may not be considered independent if the company makes payments to the charity in excess of the greater of 5% of the charity's revenues or $200,000. However, Nasdaq encourages companies to consider other situations where a director or their Family Member and the company each have a relationship with the same charity when assessing director independence.

For purposes of determining whether a lawyer is eligible to serve on an audit committee, *SEC* Rule 10A–3 under the Act generally provides that any partner in a law firm that receives payments from the issuer is ineligible to serve on that issuer's audit committee. In determining whether a director may be considered independent for purposes other than the audit committee, payments to a law firm would generally be considered under Rule 4200(a)(15)(D), which looks to whether the payment exceeds the greater of 5% of the recipient's gross revenues or $200,000; however, if the firm is a sole proprietorship, Rule 4200(a)(15)(B), which looks to whether the payment exceeds $60,000, applies.

Paragraph (G) of the *R*[r]ule provides a different measurement for independence for investment companies in order to harmonize with the Investment Company Act of 1940. In particular, in lieu of paragraphs (A)–(F), a director who is an "interested person" of the company as defined in *S*[s]ection 2(a)(19) of the Investment Company Act of 1940, other than in his or her capacity as a member of the board of directors or any board committee, [would]*shall* not be considered [to be] independent.

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4350. Qualitative Listing Requirements for Nasdaq National Market and Nasdaq SmallCap Market Issuers Except for Limited Partnerships

No change.

(a) Applicability

(1)through (4) No change.

(5) Effective Dates/Transition. In order to allow companies to make necessary adjustments in the course of their regular annual meeting schedule, and consistent with [Exchange Act]*SEC* Rule 10A–3, Rules 4300 and 4350 are effective as set out in this subsection. During the transition period between November 4, 2003 and the effective date of Rules 4200 and 4350, companies that have not brought themselves into compliance with these [r]*R*ules [must]*shall* continue to comply with Rules 4200–1 and 4350–1, which consist of sunsetting sections of previously existing Rules 4200 and 4350.

The provisions of Rule 4200(a) and Rule 4350(c), (d) and (m) regarding director independence, independent committees, and notification of noncompliance shall be implemented by the following dates:

• July 31, 2005, for foreign private issuers and small business issuers (as defined in *SEC* Rule 12b–2); and

• For all other listed issuers, by the earlier of: (1) The listed issuer's first annual shareholders meeting after January 15, 2004; or (2) October 31, 2004.

In the case of an issuer with a staggered board, with the exception of the audit committee requirements, the issuer shall have until their second annual meeting after January 15, 2004, but not later than December 31, 2005, to implement all new requirements relating to board composition, if the issuer would be required to change a director who would not normally stand for election at an earlier annual meeting. Such issuers shall comply with the audit committee requirements pursuant to the implementation schedule bulleted above.

[Issuers that have listed or shall be listed in conjunction with their initial public offerings shall be afforded exemptions from all board composition requirements consistent with the exemptions afforded in Rule 10A–3(b)(1)(iv)(A) under the Act. That is, for each committee that the company adopts, the company shall have one independent member at the time of listing, a majority of independent members within 90 days of listing and all independent members within one year.] *A company listing in connection with its initial public offering shall be permitted to phase in its compliance with the independent committee requirements set forth in Rule 4350(c) on the same schedule as it is permitted to phase in its compliance with the independent audit committee requirement pursuant to SEC Rule 10A–3(b)(1)(iv)(A). Accordingly, a company listing in connection with its initial public offering shall be permitted to phase in its compliance with the independent committee requirements set forth in Rule 4350(c) as follows: (1) One independent member at the time of listing; (2) a majority of independent members within 90 days of listing; and (3) all independent members within one year of listing. Furthermore, a company listing in connection with its initial public offering shall have twelve months from the date of listing to comply with the majority independent board requirement in Rule 4350(c).* It should be noted, however, that *pursuant to SEC Rule 10A–3(b)(1)(iii)* investment companies are not afforded the[se] exemptions under *SEC* Rule 10A–*3(b)(1)(iv)*. Issuers may choose not to adopt a compensation or nomination committee and may instead rely upon a majority of the independent directors to discharge responsibilities under [the r]*R*ule[s] *4350(c)*. [These issuers shall be required to meet the majority independent board requirement within one year of listing.] *For purposes of Rule 4350 other than Rule 4350(d)(2)(A)(ii) and Rule 4350(m), a company shall be considered to be listing in conjunction with an initial public offering if, immediately prior to listing, it does not have a class of common stock registered under the Act. For purposes of Rule 4350(d)(2)(A)(ii) and Rule 4350(m), a company shall be considered to be listing in conjunction with an initial public offering only if it meets the conditions in SEC Rule 10A–3(b)(1)(iv)(A) under the Act, namely, that the company was not, immediately prior to the effective date of a registration statement, required to file reports with the Commission pursuant to Section 13(a) or 15(d) of the Act.*

Companies that are emerging from bankruptcy or have ceased to be Controlled Companies within the meaning of Rule 4350(c)(5) shall be permitted to phase-in independent nomination and compensation committees and majority independent boards on the same schedule as companies listing in conjunction with their initial public offering. It should be noted, however, that a company that has ceased to be a Controlled Company within the meaning of Rule 4350(c)(5) must comply with the audit committee requirements of Rule 4350(d) as of the date it ceased to be a Controlled Company. Furthermore, the executive sessions requirement of Rule 4350(c)(2) applies to Controlled Companies as of the date of listing and continues to apply after it ceases to be controlled.

Companies transferring from other markets with a substantially similar requirement shall be afforded the balance of any grace period afforded by the other market. Companies transferring from other listed markets that do not have a substantially similar requirement shall be afforded one year from the date of listing on Nasdaq. This transition period is not intended to supplant any applicable requirements of Rule 10A–3 under the Act.

The limitations on corporate governance exemptions to foreign private issuers shall be effective July 31, 2005. However, the requirement that a foreign issuer disclose the receipt of a corporate governance exemption from Nasdaq shall be effective for new listings and filings made after January 1, 2004.

Rule 4350(n), requiring issuers to adopt a code of conduct, shall be effective May 4, 2004.

Rule 4350(h), requiring audit committee approval of related party transactions, shall be effective January 15, 2004.

The remainder of Rule 4350(a) and Rule 4350(b) are effective November 4, 2003.

(b)–(g) No change

(h) Conflict of Interest

Each issuer shall conduct an appropriate review of all related party transactions for potential conflict of interest situations on an ongoing basis and all such transactions [must] *shall* be approved by the company's audit committee or another independent body of the board of directors. For purposes of this rule, the term "related party transaction" shall refer to transactions required to be disclosed pursuant to SEC Regulation S–K, Item 404. *However, in the case of small business issuers (as that term is defined in SEC Rule 12b–2), the term "related party transactions" shall refer to transactions required to be disclosed pursuant to SEC Regulation S–B, Item 404, and in the case of non-U.S. issuers, the term "related party transactions" shall refer to transactions required to be disclosed pursuant to Form 20–F, Item 7.B.*

(i)–(n) No change.

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II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, Nasdaq included statements concerning the purpose of and basis for the proposed rule change, as amended, and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in item IV below. Nasdaq has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

According to Nasdaq, the purpose of this rule filing, as amended, is to change certain provisions of Nasdaq's existing corporate governance standards to conform to the corporate governance standards of another self-regulatory organization and to provide additional transparency to such standards.

(i) Rule 4200(a)(15)(B) Look-Back Provision

NASD Rule 4200(a)(15)(B) currently provides that a person cannot be an independent director if the person has accepted any payments from the company or a subsidiary or parent of the company in excess of $60,000 during the current or any of the past three fiscal years. The proposed rule filing would eliminate the use of an issuer's fiscal year in determining the three-year look-back period set forth in NASD Rule 4200(a)(15)(B). Under the proposed new rule, as amended, the look-back period would be any period of 12 consecutive months within the three years preceding the date independence is to be determined. For example, if independence were to be determined as of an issuer's annual meeting scheduled for May 1, 2004, the look-back period under the proposed new NASD Rule 4200(a)(15)(B) would be from May 1, 2001, to May 1, 2004. Under the current NASD Rule 4200(a)(15)(B), the look-back period depends on when the issuer's fiscal year begins. Using the same example above, with independence to be determined as of the issuer's annual meeting scheduled for May 1, 2004, and with the issuer's fiscal year beginning on October 1, the look-back period would be from October 1, 2000, to May 1, 2004. Nasdaq believes that the proposed modification to NASD Rule 4200(a)(15)(B) is appropriate because it introduces a simpler calculation that is not dependent on an issuer's particular fiscal year-end.

(ii) Clarification of the Transition Rules for a Company Emerging From Bankruptcy or a Company That Ceases To Be a Controlled Company

The proposed rule change, as amended, also would clarify that a company emerging from bankruptcy or a company that ceases to be a Controlled Company (as defined by NASD Rule 4350(c)(5)) will be given the same schedule for compliance with NASD Rule 4350's independent committees and majority independent board requirements as a company seeking to be listed in connection with an initial public offering ("IPO") is given pursuant to NASD Rule 4350(a)(5). In particular, for each committee that the company adopts (other than the audit committee) the company would be required to have one independent member at the time of listing, a majority of independent members within 90 days of listing, and all independent members within one year of listing. Furthermore, the company would be required to have a majority independent board within one year of listing. Nasdaq states that it has historically given a company emerging from bankruptcy or a company that ceases to be a Controlled Company the same grace period for compliance with NASD Rule 4350 as it provides a company seeking to be listed in connection with an IPO. Nasdaq believes that providing such companies with a reasonable period of time to make adjustments to comply with the requirements of Rule 4350 is reasonable and appropriate under the circumstances. Likewise, pursuant to section 303A of the Listed Company Manual of the New York Stock Exchange ("NYSE"), the NYSE permits a company emerging from bankruptcy and a company that has ceased to be Controlled Company to phase-in independent nomination and compensation committees and majority independent boards on the same schedule as companies listing in conjunction with an IPO. Accordingly, Nasdaq believes the proposed rule filing, as amended, will conform Nasdaq's corporate governance standards to the NYSE's corporate governance standards, creating more uniformity across market centers with respect to transition rules for these companies.

(iii) Clarification of the Definition of "Related Party Transaction"

Further, the proposed rule change, as amended, would clarify the definition of the term "related party transaction" in NASD Rule 4350(h) with respect to small business issuers and non-U.S. issuers. The term "related party transaction" is currently defined in NASD Rule 4350(h) as any transaction that must be disclosed pursuant to SEC Regulation S–K, Item 404. Small business issuers and non-U.S. issuers, however, are not subject to SEC Regulation S–K, Item 404, but are instead subject to SEC Regulation S–B, Item 404, and Form 20–F, Item 7.B, respectively. Accordingly, the proposed rule change, as amended, corrects this discrepancy by clarifying that the term "related party transaction" for purposes of small business issuers shall refer to transactions required to be disclosed under SEC Regulation S–B, Item 404, and, with respect to non-U.S. issuers, the term "related party transactions" shall refer to those transactions required to be disclosed under Form 20–F, Item 7.B.[6]

2. Statutory Basis

Nasdaq believes that the proposed rule change, as amended, is consistent with the provisions of section 15A of the Act,[7] in general, and furthers the objectives of section 15A(b)(6) of the Act,[8] in particular, in that it is designed to foster cooperation and coordination with persons engaged in regulating and processing information with respect to, and facilitating transactions in securities, to remove impediments to a free and open market and a national market system, and, in general, to protect investors and the public interest. Nasdaq believes the proposed rule change will benefit investors, issuers, issuers' counsel, and member firms by providing additional transparency to Nasdaq's corporate governance standards and promoting greater uniformity with the existing corporate governance standards of the NYSE. Nasdaq also believes additional transparency and greater uniformity will reduce administrative costs associated with compliance with Nasdaq's corporate governance standards.

B. Self-Regulatory Organization's Statement on Burden on Competition

Nasdaq does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received for this proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The proposed rule change has been designated by Nasdaq as a "non-controversial" rule change pursuant to section 19(b)(3)(A) of the Act[9] and subparagraph (f)(6) of Rule 19b–4 thereunder.[10]

The foregoing proposed rule change: (1) Does not significantly affect the protection of investors or the public interest, (2) does not impose any significant burden on competition, and (3) by its terms does not become operative for 30 days after the date of this filing, or such shorter time as the Commission may designate, if consistent with the protection of investors and the public interest. Furthermore, the NASD gave the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change. Consequently, the proposed rule change has become effective pursuant to section 19(b)(3)(A) of the Act[11] and Rule 19b–4(f)(6) thereunder.[12]

Pursuant to Rule 19b–4(f)(6)(iii),[13] a proposed "non-controversial" rule change does not become operative for 30 days after the date of filing, or such shorter time as the Commission may designate if consistent with the protection of investors and the public interest. Nasdaq has requested that the Commission waive the 30-day operative delay, to permit the NASD to implement the proposal immediately.

The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest. The Commission believes that the proposed rule change makes reasonable modifications that will ease the application of certain of Nasdaq's corporate governance rules for listed issuers and conforms others to those of the NYSE, and that acceleration of the operative date is appropriate to expedite their implementation. Therefore, the Commission designates the proposed rule change to become operative immediately.[14]

At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.[15]

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send e-mail to *rule-comments@sec.gov*. Please include File Number SR–NASD–2004–080 on the subject line.

Paper Comments

- Send paper comments in triplicate to Jonathan G. Katz, Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549–0609.

All submissions should refer to File Number SR–NASD–2004–080. This file number should be included on the subject line if e-mail is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing also will be available for inspection and copying at the principal office of Nasdaq. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASD–2004–080 and should be submitted on or before July 20, 2004.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[16]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 04–14678 Filed 6–28–04; 8:45 am]

BILLING CODE 8010–01–U

[6] The Commission notes that the proposed rule change also includes additional amendments to the text of NASD Rules 4200 and 4350 and IM–4200 that do not introduce substantive changes.

[7] 15 U.S.C. 78*o*–3.

[8] 15 U.S.C. 78*o*–3(b)(A).

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(6).

[11] 15 U.S.C. 78s(b)(3)(A).

[12] 17 CFR 240.19b–4(f)(6).

[13] 17 CFR 240.19b–4(f)(6)(iii).

[14] For the purposes only of accelerating the operative date of this proposal, the Commission has considered the proposed rules impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[15] For purposes of calculating the 60-day abrogation period, the Commission considers the period to commence on June 17, 2004, the date that Nasdaq filed Amendment No. 1.

[16] 17 CFR 200.30–3(a)(12).

SMALL BUSINESS ADMINISTRATION

[Declaration of Disaster #3585]

State of Indiana (Amendment #2)

In accordance with a notice received from the Department of Homeland Security—Federal Emergency Management Agency, effective June 22, 2004, the above numbered declaration is hereby amended to include Brown, Clay, Delaware, Greene, Henry, Jasper, Lake, Madison, Monroe, Newton, Owen, Putnam, and Tipton Counties as disaster areas due to damages caused by severe storms, tornadoes, and flooding occurring on May 27, 2004, and continuing.

In addition, applications for economic injury loans from small businesses located in the contiguous counties of Fayette, Jay, LaPorte, Porter, Randolph, Sullivan, Vigo, and Wayne in the State of Indiana; and Cook, Kankakee, and Will Counties in the State of Illinois may be filed until the specified date at the previously designated location. All other counties contiguous to the above named primary counties have been previously declared.

All other information remains the same, *i.e.*, the deadline for filing applications for physical damage is August 2, 2004, and for economic injury the deadline is March 3, 2005.

(Catalog of Federal Domestic Assistance Program Nos. 59002 and 59008)

Dated: June 23, 2004.

Cheri L. Cannon,

Acting Associate Administrator for Disaster Assistance.

[FR Doc. 04–14713 Filed 6–28–04; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

[Declaration of Disaster #3590]

Commonwealth of Kentucky (Amendment #1)

In accordance with a notice received from the Department of Homeland Security—Federal Emergency Management Agency, effective June 18, 2004, the above numbered declaration is hereby amended to establish the incident period for this disaster as beginning on May 26, 2004 and continuing through June 18, 2004.

All other information remains the same, *i.e.*, the deadline for filing applications for physical damage is August 9, 2004, and for economic injury the deadline is March 10, 2005.

(Catalog of Federal Domestic Assistance Program Nos. 59002 and 59008)

Dated: June 23, 2004.

Cheri L. Cannon,

Acting Associate Administrator for Disaster Assistance.

[FR Doc. 04–14714 Filed 6–28–04; 8:45 am]

BILLING CODE 8025–01–P

SMALL BUSINESS ADMINISTRATION

Public Federal Regulatory Enforcement Fairness Roundtable; Region X Regulatory Fairness Board

The Small Business Administration Region X Regulatory Fairness Board and the SBA Office of the National Ombudsman will hold a Public Roundtable on Wednesday, July 28, 2004 at 8:30 a.m. at the State Capitol Building, Hearing Room E, 900 Court Street, NE., Salem, OR 97301–4042, to provide small business owners and representatives of trade associations with an opportunity to share information concerning the federal regulatory enforcement and compliance environment.

Anyone wishing to attend or to make a presentation must contact Moe Mowery in writing or by fax, in order to be put on the agenda. Moe Mowery, Business Development Officer, Small Business Administration Portland District Office, 1515 S.W. Fifth Avenue, Suite 1050, Portland, OR 97201–5494, phone (503) 326–5209, fax (202) 481–4411, e-mail: *marlin.mowery@sba.gov*.

For more information, see our Web site at *http://www.sba.gov/ombudsman*.

Dated: June 23, 2004.

Peter Sorum,

Senior Advisor, Office of the National Ombudsman.

[FR Doc. 04–14712 Filed 6–28–04; 8:45 am]

BILLING CODE 8025–01–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

[Docket No. RSPA–04–17401]

Pipeline Safety: Development of Class Location Change Waiver Criteria

AGENCY: Office of Pipeline Safety, Research and Special Programs Administration, DOT.

ACTION: Notice; criteria for class location change waivers.

SUMMARY: This notice announces the availability of the criteria that the Office of Pipeline Safety (OPS) will use in considering waiver applications submitted by operators of natural gas pipeline segments that have experienced a change in class location. A class location change results from new construction in the vicinity of a pipeline segment and, in the absence of a waiver, triggers a requirement that the maximum allowable operating pressure be confirmed or revised. The criteria matrix provides information and guidance to pipeline operators concerning the specific pipe design and operating parameters within which OPS is likely to consider a class location waiver application to be consistent with pipeline safety.

FOR FURTHER INFORMATION CONTACT: Joy Kadnar, (tel: 202–366–0568; e-mail *joy.kadnar@rspa.dot.gov* regarding the subject matter of this notice. A copy of the new criteria for consideration of gas pipeline Class Location waiver applications can be accessed in the docket captioned above on the DOT's Docket Management System Web site at: *http://dms.dot.gov*. Additional information about RSPA/OPS Class Location waiver criteria can be found at *http://primis.rspa.dot.gov/gasimp*.

ADDRESSES: For access to the docket to read background documents or comments, go to *http://dms.dot.gov* at any time or to Room PL–40 on the plaza level of the Nassif Building, 400 Seventh Street, SW., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal Holidays.

SUPPLEMENTARY INFORMATION:

Background

The criteria document available in the docket establishes guidelines for the consideration of requests for waiver of the requirement at 49 CFR 192.611 to confirm or revise the maximum allowable operating pressure (MAOP) of a natural gas pipeline after a change in class location has occurred. If granted, a class location waiver would allow a pipeline operator to perform alternative risk control activities based on the principles and requirements of the Integrity Management Program in lieu of pipe replacement or pressure reduction.

On December 15, 2003, the Office of Pipeline Safety (OPS) published a Final Rule requiring operators of gas transmission pipelines to develop and implement integrity management programs for their pipelines in high consequence areas (68 FR 69778; Dec. 15, 2003). The cost-benefit analysis in the rule states that:

> Another benefit to be realized from implementing this rule is reduced cost to the pipeline industry for assuring safety in areas along pipelines with relatively more population. The improved knowledge of pipeline integrity that will result from

implementing this rule will provide a technical basis for providing relief to operators from current requirements to reduce operating stresses in pipelines when population near them increases. Regulations currently require that pipelines with higher local population density operate at lower pressures. This is intended to provide an extra safety margin in those areas. Operators typically replace pipeline when population increases, because reducing pressure to reduce stresses reduces the ability of the pipeline to carry gas. Areas with population growth typically require more, not less, gas. Replacing pipeline, however, is very costly. Providing safety assurance in another manner, such as by implementing this rule, could allow RSPA/OPS to waive some pipe replacement. RSPA/OPS estimates that such waivers could result in a reduction in costs to industry of $1 billion over the next 20 years, with no reduction in public safety.

In addition to being factored into the cost-benefit analysis of the Integrity Management Program rule, the technical soundness of issuing class location waivers has been considered in connection with the following regulations, standards, and programs:

• The Risk Management Demonstration Program
• The Integrity Management Program regulations (49 CFR Part 192, Subpart O)
• The development of ASME Standard B31.8S "Managing System Integrity of Gas Pipelines"
• Various requests for waiver regarding compliance activities in class location change areas

The provision of class location waivers, where warranted, is intended to benefit both the public and pipeline operators. First, within the waiver area the pipeline operator will be conducting in-line inspections and other assessment methods, substantially increasing the operator's knowledge of the integrity of pipe structures and potentially accelerating the identification and repair of actionable anomalies that could pose a threat to the public and environment. Second, in addition to performing in-line inspections of the pipe located within the waiver areas, in most cases, operators will perform in-line inspection and repairs of any actionable anomalies identified up to 25 miles upstream and downstream of the waiver area, substantially increasing the protection afforded to populated and environmentally sensitive areas along the right of way. Third, provision of a class location waiver may avoid the delivery interruptions, supply shortages, and additional costs associated with excavating and replacing the pipe in the affected areas.

Candidates for Waiver Consideration

The vehicle for an operator seeking a class location waiver will be through the normal case-by-case waiver approval process. Under 49 U.S.C. 60118, OPS may grant a waiver of any regulatory requirement if granting the waiver is "not inconsistent with pipeline safety." Therefore, each operator submitting a waiver request has the burden of demonstrating that the proposed waiver would not be inconsistent with pipeline safety with respect to the particular pipe in the affected area. Each waiver request is also subject to public notice and comment. Operators of intrastate pipelines are required to submit waiver requests at the state level.

Beginning in 2004, requests for class location waivers will be considered for a number of candidate sites. During this initial period, OPS will gather data to assess whether the integrity management programs and other alternative risk control activities these waivers would be conditioned upon are being implemented effectively. The monitoring of compliance with the required activities will be conducted through periodic operator reporting requirements as well as scheduled pipeline inspections. If, after a class location waiver is granted, OPS determines that the waiver is no longer consistent with public safety, OPS may take appropriate regulatory action up to and including retraction of the waiver and requiring immediate compliance with the MAOP restrictions otherwise applicable to the changed class location. Any pipeline or pipeline section for which a class location waiver is granted remains subject to all other requirements of 49 CFR Parts 190, 191, and 192.

Criteria

The age and manufacturing process of the pipe, construction processes used and operating and maintenance history are all significant factors that must be considered in the waiver process. Additionally, certain threshold requirements must be met in order for a pipeline section to be considered a candidate site. Among these requirements are:

• No pipe segments changing to Class 4 locations will be considered
• No bare pipe will be considered
• No pipe containing wrinkle bends will be considered
• No pipe segments operating above 72% SMYS will be considered for a Class 3 waiver
• Records must be produced that show a hydrostatic test to at least 1.25 x MAOP
• In-line inspection must have been performed with no significant anomalies identified that indicate systemic problems
• Up to 25 miles of pipe either side of the waiver location must be included in the pipeline company's Integrity Management Program and periodically inspected with an in-line inspection technique

While each waiver request is considered in its entirety, requests involving pipelines with operating conditions reflecting higher risk will merit more rigorous scrutiny and require increasing levels of justification. The criteria document outlines in more detail the specific parameters of pipe design and operating conditions that OPS considers in reviewing class location waiver requests. It contains three categories specifying: (1) The parameters within which a waiver request is likely to be considered consistent with pipeline safety; (2) the parameters within which a request is less likely to be considered consistent with pipeline safety; and (3) those within which a request is unlikely to be considered consistent with pipeline safety. These criteria reflect OPS' current thinking and are subject to change as more experience with the issuance of class location waivers is gained.

Notification Requirements

Under 49 CFR 192.611(d) class location change sites have a 24-month remediation time limit that begins with the identification of the site. Accordingly, operators who have candidate sites should submit written notice to OPS of their intent to request a class location waiver as early in the 24-month period as possible. With respect to intrastate pipelines, since state agency approval is required, the operator should submit the notice to both the applicable state agency and OPS. In the notification, the operator must include the following information:

• A list of the proposed waiver sites including their beginning and ending mileposts and a map of the class change location(s), adjacent housing and other structures (within the 1320-foot corridor, or C–FER Circle if potential impact radius is greater than 660 feet (must have actual data, do not prorate)), identification of current and previous class location designation, and the reason for the class change. The operator shall indicate when this condition changed creating the new class location area and will provide verification of those date changes.
• Attributes associated with the inspection area containing the proposed waiver location(s) including:
  ◦ Pipe Vintage
    —Date of installation

—Pipe manufacturer
- Diameter, wall thickness, grade and seam type
- Coating type
- Depth of Cover
- Local geology and risks associated with the terrain
- Maximum Allowable Operating Pressure (MAOP) (revised MAOP, if applicable); historical maximum and minimum operating pressure
- Hydrostatic test records
- Girth weld radiography records
- In-line inspection records (date launched, tool type, vendor or operator evaluated log, dig records, was the tool tolerance accurately reflected in digs)
- Cathodic Protection records

• Identify the inspection area containing the proposed waiver location(s).

• Limits of HCAs within the inspection area containing the proposed waiver location(s), if applicable.

• Direct Assessment results for the proposed waiver area (ECDA, SCCDA, and coating)

• Any incidents associated with the inspection area containing the proposed waiver location(s) (both reportable and non reportable)

• History of leaks on the pipeline in the inspection area containing the proposed waiver location(s) (both reportable and non reportable)

• List of all repairs on the pipeline within the inspection area containing the proposed waiver location(s).

• On-going damage prevention initiatives on the pipeline within the inspection area containing the proposed waiver location(s) and a discussion of its effectiveness.

• A list of all Safety Related Condition Reports related to line pipe integrity submitted on the inspection area containing the proposed waiver location(s).

• A summary of the integrity threats to which the pipe within the site is susceptible based on Part 192 criteria.

• An in-line inspection schedule and a hydrostatic testing schedule (if a valid in-line inspection and hydrostatic test have not already been conducted). These inspections/tests must be scheduled such that they will be completed, and any actionable anomalies remediated in accordance with Part 192, Subpart O, prior to the end of the 24-month compliance window. The operator shall provide 30 days prior notice of any ILI or direct assessments to be performed within the inspection area containing the waiver location(s). **Note:** Final approval of the waiver will be based on the results of the hydrostatic test and ILI results and remedial activities.

• The operator must determine and provide certification that the inspections/activities associated with this site will not impact or defer any of the operator's assessments for HCAs under Part 192, Subpart O, particularly those associated with the most significant 50%.

• A summary list of any additional proposed alternative risk control activities for each candidate site, including any sites not located in a HCA (*i.e.*, inspections and assessments, electrical surveys, increased patrolling, leak surveys, public education, etc. above and beyond the current requirements of Part 192). Include the mileposts within which each activity would be conducted (additional mileage upstream and downstream of the waiver area is expected) and the proposed time interval for performing the activities on an ongoing basis. Note that OPS may require that the scope or the interval of any proposed alternative risk control activity be modified or require additional activities before granting a waiver.

• Describe the safety benefit both to the specific waiver request site, and areas outside the waiver location. This should specifically include the number of residences and identified sites at the proposed waiver location(s) and within the inspection area containing the waiver location(s).

Reporting Requirements

Within three months following approval of a class location waiver and annually thereafter, operators will be required to periodically report the following:

• Define the economic benefit to the company. This should address both the cost avoided from not replacing the pipe as well as the added costs of the inspection program (required for the initial report only).

• The results of any ILI or direct assessments performed within the inspection area containing the waiver location(s) during the previous year.

• Any new integrity threats identified within the inspection area containing the waiver location(s) during the previous year.

• Any encroachment in the inspection area including the waiver location(s) including the number of new residences or gathering areas.

• Any incidents associated with the inspection area containing the waiver location(s) that occurred during the previous year. (both reportable and non reportable)

• Any leaks on the pipeline in the inspection area containing the waiver location(s) that occurred during the previous year. (both reportable and non reportable)

• List of all repairs on the pipeline the inspection area containing the waiver location(s) made during the previous year.

• On-going damage prevention initiatives on the pipeline in the inspection area containing the waiver location(s) and a discussion on its success.

• Any mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which the waiver applies.

Supplemental Reporting

To the extent possible, the pipeline company should provide the following information with the first annual report:

• Describe the benefit to the public in terms of energy availability. Availability should address the benefit of avoided disruptions required for pipe replacement and the benefit of maintaining system capacity.

Authority: 49 U.S.C. 60102, 60109, 60117.

Issued in Washington, DC, on June 24, 2004.

Richard D. Huriaux,

Director, Technical Standards, Office of Pipeline Safety.

[FR Doc. 04–14725 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

[Docket No. RSPA–03–17375; Notice 2]

Pipeline Safety: Grant of Waiver; GulfTerra Field Services LLC

AGENCY: Research and Special Programs Administration (RSPA); U.S. Department of Transportation (DOT).

ACTION: Notice; grant of waiver.

SUMMARY: GulfTerra Field Services LLC (GTFS), requested a waiver of compliance with the regulatory requirements at 49 CFR 192.619(a)(2)(ii), 192.503, and 192.505 for certain offshore pipeline segments of the deepwater Phoenix Gas Gathering System (Phoenix). GTFS is requesting a waiver from the post-construction hydrotesting requirement for selected segments of the Phoenix system.

SUPPLEMENTARY INFORMATION:

Background

GTFS, a wholly owned subsidiary of GulfTerra Energy Partners L.P., has entered into a gas gathering agreement with Kerr McGee Oil & Gas Corporation and the Devon Louisiana Corporation to design, build, own, and operate the Phoenix Gas Gathering System (Phoenix). GTFS will transport production fuel from the Red Hawk Spar, a deepwater fuel production facility in the Gulf of Mexico, to the Pioneer Platform, an existing pipeline facility located approximately 76 miles downstream.

GTFS requested a waiver of compliance with the requirements at 49 CFR 192.619(a)(2)(ii), 192.503, and 192.505 based on its contention that it is unnecessary to hydrostatically test this pipeline. GTFS asserts that a hydrostatic test will not demonstrate the strength and integrity of the pipeline because the pipeline is designed of heavy wall pipe and it will not experience the wall stress intended to be produced by a hydrotest. The heavy wall pipe is being used to prevent the collapse of the pipeline in the face of the huge external pressures exerted on it at a water depth of 5,300 feet. GTFS proposes to perform alternative risk control activities instead of the pressure test regulations.

After reviewing the waiver request, RSPA/OPS published a notice inviting interested persons to comment on whether a waiver should be granted (Notice 1) (69 FR 16338; March 29, 2004). RSPA/OPS stated that it was considering if a hydrotest of this pipeline was necessary and if the alternative risk control activities proposed by GTFS will yield an equivalent or greater degree of safety.

Comments on Proposed Waiver

Comments were received from Carl Langer (a private citizen) and the U.S. Department of the Interior, Minerals Management Service (MMS). Each substantive comment is addressed below:

1. Both commenters noted that a hydrotest is a means of ensuring that the finished pipeline meets all quality requirements.

RSPA/OPS agrees that a hydrotest is one of several quality control checks that are generally used to ensure quality construction of a pipeline. For the Phoenix pipeline, however, GTFS has demonstrated that a hydrotest, as required by 49 CFR part 195, will not produce stresses in the pipe wall sufficient to demonstrate the integrity of the pipe because the Phoenix pipeline uses heavy wall pipe. Furthermore, RSPA/OPS sees no added value in performing a hydrotest on this pipeline. GulfTerra has committed to perform several additional quality control measures on this pipeline throughout its construction to ensure its integrity. These additional risk control measures are listed at the end of this document.

2. Mr. Langer thought it prudent to require a hydrotest as a means of applying pressure on pipeline project managers to eliminate as many human errors as possible.

Although no one can disagree that humans make mistakes, the purpose of a hydrotest has never been to apply additional pressure on pipeline project managers. To the contrary, the purpose of a hydrotest is to impose wall stresses that are sufficient to expose defects in the pipeline.

3. Both commenters mentioned that a hydrotest can be useful in detecting small pipeline leaks due to minor defects and not necessarily major pipeline failures.

The intent of the hydrotest regulation is to produce stresses in the pipe wall that are sufficient to expose defects in the pipe prior its operation. Because this pipeline is built using heavier wall pipe and is under huge compressive stresses from more than a mile of water, a hydrotest as required by the gas pipeline safety regulations will not produce wall stresses high enough to detect leaks.

4. Mr. Langer commented on the consequences of a leaking hydrocarbon pipeline and how negative public opinion could result in a suspension of operations for an offshore oil producing facility in the event of a major crude oil pipeline break. He stated that it is better to verify that the pipeline is free of leaks during construction—before hydrocarbons are introduced into the pipeline. He also suggested that a sizing pig be used in addition to a hydrotest.

The Phoenix system is a natural gas pipeline, not a hazardous liquid pipeline. Because of the different characteristics of gas and hazardous liquids, the impact of gas pipeline incidents on an offshore pipeline facility is expected to be significantly less than a similar accident involving a hazardous liquid pipeline. Moreover, because this is an offshore natural gas pipeline facility, there would be no immediate safety hazard to the general public. RSPA/OPS expects—and the federal pipeline safety regulations require—GTFS to take actions that are necessary to ensure the safe operation of its system. In addition, RSPA/OPS has the enforcement authority to impose restrictions or discontinue the use of the Phoenix pipeline in the event the facility becomes a danger to persons or the environment. Finally, the suggestion that a sizing pig be used in addition to a hydrotest is beyond the scope of this waiver.

5. Mr. Langer commented that the elimination of the hydrotest would introduce the possibility of shoddy materials and shoddy workmanship.

The Federal pipeline safety regulations set forth minimum standards for materials and constructions. In addition, GTFS has committed to perform several other quality control checks on this pipeline throughout its construction to ensure the integrity of the pipeline. GTFS is expected to comply with the federal pipeline safety regulations and the conditions of this waiver.

A waiver of the hydrotest requirement for the Phoenix system does not relieve GTFS of its responsibility to ensure that quality control procedures are adhered to during the construction of this pipeline.

6. Mr. Langer commented that there may come a time when it is cost prohibitive to dewater gas transmission pipelines after a hydrotest has been performed. However, he does not believe this to be the case with the Phoenix pipeline because this line is at a depth of only 5,300 feet.

In evaluating this waiver request, RSPA/OPS evaluated whether the proposed waiver would provide an equal or greater level of safety to that currently provided by the regulations. RSPA/OPS believes that because the Phoenix system is constructed of heavy wall pipe and located offshore at a depth of 5,300 feet, a hydrotest of this pipeline does not provide any meaningful information because the stresses produced from the tests are not sufficient to demonstrate the integrity of the pipe.

7. MMS commented that research should be performed by industry experts to determine what viable hydrotest alternatives exist and how can they be implemented.

GTFS relied on the research and expertise of Det Norske Veritas (DNV), a respected international and independent foundation involved in safeguarding life, property, and the environment at sea, and designed this pipeline to meet DNV's Offshore Standard for Submarine Pipeline Systems (DNV–OS–F101, Jan. 2003). DNV publishes Offshore Service Specifications, Offshore Standards, and Recommended Practices for ships, offshore units and installations. It also provides classification, certification, and other verification and consulting services for general use by the offshore industry. For additional information on

DNV's research and expertise dealing with offshore pipeline facilities, they are located on the Web and can be reached at *http://exchange.dnv.com.*

Grant of Waiver

For the reasons explained above and in Notice 1, and in light of the equivalent level of safety provided by the alternative risk control activities, RSPA/OPS finds that the request for waiver is consistent with pipeline safety. Therefore, GTFS's request for waiver of compliance with 49 CFR 192.619(a)(2)(ii), 192.503, and 192.505 is granted subject to GTFS compliance with the following conditions:

1. Utilize thick wall, high strength, and high quality DSAW pipe;

2. Perform a pipe mill hydrotest on each pipe joint equivalent to 95% specified minimum yield strength (SMYS) to detect defects in the seam weld and prevent the deployment of defective pipe joints;

3. Perform extensive inspection and quality control during the line pipe manufacture, transport, fabrication, and installation to prevent pipe damage;

4. Utilize Automated Ultrasonic Inspection (AUT) for inspection of offshore welds to improve defect detection in the girth weld and to improve the weld quality during the pipeline and steel catenary riser fabrication;

5. Subject all buckle arrestors to complete radiographic and magnetic particle inspection, including radiographic inspection of all buckle arrestor to line pipe welds;

6. Perform complete radiographic inspection and hydrotesting of all welds connecting subsea valves and assemblies to the pipeline;

7. Perform a leak test of the pipeline's subsea tie-in flange that connects to the VR 397 riser flange; and

8. Perform factory acceptance hydrotests of all subsea "wye", tee, ball valve, and check valve assemblies.

Issued in Washington, DC, on June 24, 2004.

William H. Gute,

Acting Deputy Associate Administrator for Pipeline Safety.

[FR Doc. 04–14726 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Docket No. AB–33 (Sub–No. 216X)]

Union Pacific Railroad Company—Abandonment Exemption—in Weld County, CO

On June 15, 2004, Union Pacific Railroad Company (UP) filed with the Board a petition [1] under 49 U.S.C. 10502 for exemption from the provisions of 49 U.S.C. 10903 to abandon a 1.12-mile portion of its Monfort Industrial Lead between milepost 141.12 and milepost 140.00 near Kersey, in Weld County, CO.[2] The line traverses United States Postal Service Zip Code 80644 and includes no stations.

The line contains both federally granted rights-of-way and fee title property. Any documentation in UP's possession will be made available promptly to those requesting it.

The interest of railroad employees will be protected by the conditions set forth in *Oregon Short Line R. Co.—Abandonment—Goshen*, 360 I.C.C. 91 (1979).

By issuance of this notice, the Board is instituting an exemption proceeding pursuant to 49 U.S.C. 10502(b). A final decision will be issued by October 1, 2004.

Any offer of financial assistance (OFA) under 49 CFR 1152.27(b)(2) will be due no later than 10 days after service of a decision granting the petition for exemption. Each OFA must be accompanied by a $1,100 filing fee. *See* 49 CFR 1002.2(f)(25).

All interested persons should be aware that, following abandonment of rail service and salvage of the line, the line may be suitable for other public use, including interim trail use. Any request for a public use condition under 49 CFR 1152.28 or for trail use/rail banking under 49 CFR 1152.29 will be due no later than July 22, 2004. Each trail use request must be accompanied by a $200 filing fee. *See* 49 CFR 1002.2(f)(27).

All filings in response to this notice must refer to STB Docket No. AB–33 (Sub-No. 216X) and must be sent to: (1) Surface Transportation Board, 1925 K Street, NW., Washington, DC 20423–0001; and (2) Mack H. Shumate, Jr., 101 North Wacker Drive, Room 1920, Chicago, IL 60606. Replies to the UP petition are due on or before July 22, 2004.

Persons seeking further information concerning abandonment procedures may contact the Board's Office of Public Services at (202) 565–1592 or refer to the full abandonment or discontinuance regulations at 49 CFR part 1152. Questions concerning environmental issues may be directed to the Board's Section of Environmental Analysis (SEA) at (202) 565–1539. [Assistance for the hearing impaired is available through the Federal Information Relay Service (FIRS) at 1–800–877–8339.]

An environmental assessment (EA) (or environmental impact statement (EIS), if necessary) prepared by SEA will be served upon all parties of record and upon any agencies or other persons who commented during its preparation. Other interested persons may contact SEA to obtain a copy of the EA (or EIS). EAs in these abandonment proceedings normally will be made available within 60 days of the filing of the petition.

The deadline for submission of comments on the EA will generally be within 30 days of its service.

Board decisions and notices are available on our Web site at "*http://www.stb.dot.gov.*"

Decided: June 18, 2004.

By the Board, David M. Konschnik, Director, Office of Proceedings.

Vernon A. Williams,

Secretary.

[FR Doc. 04–14591 Filed 6–28–04; 8:45 am]

BILLING CODE 4915–01–P

[1] The petition was initially received on May 28, 2004, but contained conflicting information regarding ownership of the right-of-way. On June 15, 2004, a supplemental filing was received correcting the draft notice to indicate that the line contains both federally granted rights-of-way and fee title property. Accordingly, June 15, 2004, is considered to be the actual filing date and the due dates in this notice are based on that date.

[2] UP states that after abandonment the track and right-of-way will be sold to ConAgra Foods, the only shipper on the line. The shipper will then reconfigure its facility to receive larger, more efficient unit shuttle trains of grain, and the line will be converted to an industry track.

DEPARTMENT OF THE TREASURY

Fiscal Service

Renegotiation Board Interest Rate; Prompt Payment Interest Rate; Contract Disputes Act

AGENCY: Bureau of the Public Debt, Fiscal Service, Treasury.

ACTION: Notice.

SUMMARY: For the period beginning July 1, 2004 and ending on December 31, 2004, the prompt payment interest rate is 4.500 per centum per annum.

ADDRESSES: Comments or inquiries may be mailed to Mitzie Johnson, Acting Team Leader, Borrowings Accounting Team, Division of Accounting Operations, Office of Public Debt

Accounting, Bureau of the Public Debt, Parkersburg, West Virginia 26106–1328. A copy of this Notice will be available to download from *http://www.publicdebt.treas.gov.*

DATES: This notice announces the applicable interest rate for the July 1, 2004 to December 31, 2004 period.

FOR FURTHER INFORMATION CONTACT: Stephanie Brown, Director, Division of Accounting Operations, Office of Public Debt Accounting, Bureau of the Public Debt, Parkersburg, West Virginia 26106–1328, (304) 480–5181; Mitzie Johnson, Acting Team Leader, Borrowings Accounting Team, Division of Accounting Operations, Office of the Public Debt Accounting, Bureau of the Public Debt, Parkersburg, West Virginia 26106–1328, (304) 480—5166; Edward C. Gronseth, Deputy Chief Counsel, Office of the Chief Counsel, Bureau of the Public Debt, (304) 480–8692); or Latisha R. Brown, Attorney-Adviser, Office of the Chief Counsel, Bureau of the Public Debt, (202) 504–3710.

SUPPLEMENTARY INFORMATION: Although the Renegotiation Board is no longer in existence, other Federal Agencies are required to use interest rates computed under the criteria established by the Renegotiation Act of 1971 Sec. 2, Public Law 92–41, 85 Stat. 97. For example, the Contracts Disputes Act of 1978 Sec. 12, Public Law 95–563, 92 Stat. 2389 and, indirectly, the Prompt Payment Act of 1982, 31 U.S.C. 3902(a), provide for the calculation of interest due on claims at a rate established by the Secretary of the Treasury for the Renegotiation Board under Public Law 92–41.

Therefore, notice is given that the Secretary of the Treasury has determined that the rate of interest applicable, for the period beginning July 1, 2004 and ending on December 31, 2004, is 4.500 per centum per annum. This rate is determined pursuant to the above-mentioned sections for the purpose of said sections.

Dated: June 24, 2004.

Donald V. Hammond,

Fiscal Assistant Secretary.

[FR Doc. 04–14690 Filed 6–28–04; 8:45 am]

BILLING CODE 4810–39–M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Forms 8804, 8805 and 8813

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 8804, Annual Return for Partnership Withholding Tax (Section 1446), Form 8805, Foreign Partner's Information Statement of Section 1446 Withholding Tax and Form 8813, Partnership Withholding Tax Payment Voucher (Section 1446).

DATES: Written comments should be received on or before August 30, 2004, to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, room 6411, 1111 Constitution Avenue, NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the forms and instructions should be directed to Carol Savage at Internal Revenue Service, room 6407, 1111 Constitution Avenue, NW., Washington, DC 20224, or at (202) 622–3945, or through the internet at *CAROL.A.SAVAGE@irs.gov.*

SUPPLEMENTARY INFORMATION: *Title:* Form 8804, Annual Return for Partnership Withholding Tax (Section 1446); Form 8805, Foreign Partner's Information Statement of Section 1446 Withholding Tax; and Form 8813, Partnership Withholding Tax Payment Voucher (Section 1446).

OMB Number: 1545–1119.

Form Number: 8804, 8805 and 8813.

Abstract: Internal Revenue Code section 1446 requires partnerships that are engaged in the conduct of a trade or business in the United States to pay a withholding tax if they have effectively connected taxable income that is allocable to foreign partners. The partnerships use Form 8813 to make payments of withholding tax to the IRS. They use Forms 8804 and 8805 to make annual reports to provide the IRS and affected partners with information to assure proper withholding, crediting to partners' accounts and compliance.

Current Actions: There are no changes being made to the forms at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Business or other for-profit organizations and individuals.

Estimated Number of Respondents: 5,000.

Estimated Time Per Respondent: 21 hr., 37 min.

Estimated Total Annual Burden Hours: 108,100.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: June 22, 2004.

Glenn P. Kirkland,

IRS Reports Clearance Officer.

[FR Doc. 04–14720 Filed 6–28–04; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

Proposed Collection; Comment Request for Form 2848

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice and request for comments.

SUMMARY: The Department of the Treasury, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this

opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)). Currently, the IRS is soliciting comments concerning Form 2848, Power of Attorney and Declaration of Representative.

DATES: Written comments should be received on or before August 30, 2004, to be assured of consideration.

ADDRESSES: Direct all written comments to Glenn P. Kirkland, Internal Revenue Service, room 6411, 1111 Constitution Avenue NW., Washington, DC 20224.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the form and instructions should be directed to Carol Savage at Internal Revenue Service, room 6407, 1111 Constitution Avenue NW., Washington, DC 20224, or at (202) 622–3945, or through the internet at *CAROL.A.SAVAGE@irs.gov.*

SUPPLEMENTARY INFORMATION:

Title: Power of Attorney and Declaration of Representative,

OMB Number: 1545–0150.

Form Number: 2848.

Abstract: Form 2848 issued to authorize someone to act for the taxpayer in tax matters. It grants all powers that the taxpayer has except signing a return and cashing refund checks. The information on the form is used to identify representatives and to ensure that confidential information is not divulged to unauthorized persons.

Current Actions: There are no changes being made to the form at this time.

Type of Review: Extension of a currently approved collection.

Affected Public: Individuals or households; business or other for-profit organizations, not-for-profit institutions, and farms.

Estimated Number of Respondents: 800,000.

Estimated Time Per Respondent: 1 hour, 39 minutes.

Estimated Total Annual Burden Hours: 1,320,500.

The following paragraph applies to all of the collections of information covered by this notice:

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Approved: June 22, 2004.

Glenn P. Kirkland,

IRS Reports Clearance Officer.

[FR Doc. 04–14721 Filed 6–28–04; 8:45 am]

BILLING CODE 4830–01–P

Corrections

Federal Register

Vol. 69, No. 124

Tuesday, June 29, 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 COMMERCE

National Oceanic and Atmospheric Administration

[I.D. 050304F]

Atlantic Coastal Fisheries Cooperative Management Act Provisions; Application for Exempted Fishing Permit (EFP)

Correction

In notice document E4–1256 beginning on page 31588 in the issue of June 4, 2004, make the following correction:

On page 31588, in the third column, in the **DATES** section, in the second line, "August 3, 2004" should read "July 6, 2004. ".

[FR Doc. Z4–1256 Filed 6–28–04; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF DEFENSE

GENERAL SERVICES ADMINISTRATION

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

48 CFR Part 12

[FAC 2001–24; FAR Case 2004–004; Item I]

RIN 9000–AJ97

Federal Acquisition Regulation; Incentives for Use of Performance–Based Contracting for Services

Correction

In rule document 04–13618 beginning on page 34226 in the issue of Friday, June 18, 2004, make the following corrections:

§12.102 [Corrected]

1. On page 34227, in the third column, in §12.102 (g)(1), in the second line, "14313" should read, "1431".

2. On the same page, in the same column, in the same section, in the sixth and seventh lines, the phrase "performance–based contracting" should be deleted.

[FR Doc. C4–13618 Filed 6–28–04; 8:45 am]

BILLING CODE 1505–01–D

Federal Register

Tuesday,
June 29, 2004

Part II

Environmental Protection Agency

40 CFR Parts 9, 69, et al.

Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9, 69, 80, 86, 89, 94, 1039, 1048, 1051, 1065, and 1068

[OAR–2003–0012; FRL–7662–4]

RIN 2060–AK27

Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Nonroad diesel engines contribute considerably to our nation's air pollution. These engines, used primarily in construction, agricultural, and industrial applications, are projected to continue to contribute large amounts of particulate matter, nitrogen oxides, and sulfur oxides, all of which contribute to serious public health problems in the United States. These problems include premature mortality, aggravation of respiratory and cardiovascular disease, aggravation of existing asthma, acute respiratory symptoms, chronic bronchitis, and decreased lung function. We believe that diesel exhaust is likely to be carcinogenic to humans by inhalation.

Today, EPA is adopting new emission standards for nonroad diesel engines and sulfur reductions in nonroad diesel fuel that will dramatically reduce harmful emissions and will directly help States and local areas recently designated as 8-hour ozone nonattainment areas to improve their air quality. This comprehensive national program regulates nonroad diesel engines and diesel fuel as a system. New engine standards will begin to take effect in the 2008 model year, phasing in over a number of years. These standards are based on the use of advanced exhaust emission control devices. We estimate particulate matter reductions of 95 percent, nitrogen oxides reductions of 90 percent, and the virtual elimination of sulfur oxides from nonroad engines meeting the new standards. Nonroad diesel fuel sulfur reductions of more than 99 percent from existing levels will provide significant health benefits as well as facilitate the introduction of high-efficiency catalytic exhaust emission control devices as these devices are damaged by sulfur. These fuel controls will be phased-in starting in mid-2007. Today's nonroad final rule is largely based on the Environmental Protection Agency's 2007 highway diesel program.

To better ensure the benefits of the standards are realized in-use and throughout the useful life of these engines, we are also adopting new test procedures, including not-to-exceed requirements, and related certification requirements. The rule also includes provisions to facilitate the transition to the new engine and fuel standards and to encourage the early introduction of clean technologies and clean nonroad diesel fuel. We have also developed provisions for both the engine and fuel programs designed to address small business considerations.

The requirements in this rule will result in substantial benefits to public health and welfare through significant reductions in emissions of nitrogen oxides and particulate matter, as well as nonmethane hydrocarbons, carbon monoxide, sulfur oxides, and air toxics. We are now projecting that by 2030, this program will reduce annual emissions of nitrogen oxides and particulate matter by 738,000 and 129,000 tons, respectively. These emission reductions will prevent 12,000 premature deaths, over 8,900 hospitalizations, and almost a million work days lost, and will achieve other quantifiable benefits every year. The total benefits of this rule will be approximately \$80 billion annually by 2030. The substantial health and welfare benefits we are projecting for this final action exceed those we anticipated at the time of this proposal. Costs for both the engine and fuel requirements will be many times less, at approximately \$2 billion annually.

DATES: This final rule is effective on August 30, 2004.

The incorporation by reference of certain publications listed in this regulation is approved by the Director of the Federal Register as of August 30, 2004.

ADDRESSES: EPA has established a docket for this action under Docket ID Nos. OAR–2003–0012 and A–2001–28. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the Air Docket in the EPA Docket Center, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Carol Connell, Assessment and Standards Division, Office of Transportation and Air Quality, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; telephone number: (734) 214–4349; fax number: (734) 214–4050; e-mail address: *connell.carol@epa.gov*, or Assessment and Standards Division Hotline; telephone number: (734) 214–4636; e-mail address: *asdinfo@epa.gov*.

SUPPLEMENTARY INFORMATION:

Does This Action Apply To Me?

This action may affect you if you produce or import new diesel engines which are intended for use in nonroad vehicles or equipment, such as agricultural and construction equipment, or if you produce or import such nonroad vehicles or equipment. It may also affect you if you convert nonroad vehicles or equipment, or the engines used in them, to use alternative fuels. It may also affect you if you produce, import, distribute, or sell nonroad diesel fuel.

The following table gives some examples of entities that may have to follow the regulations. But because these are only examples, you should carefully examine the regulations in 40 CFR parts 80, 89, 1039, 1065, and 1068. If you have questions, call the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this preamble:

Category	NAICS codes[a]	SIC codes[b]	Examples of potentially regulated entities
Industry	333618	3519	Manufacturers of new nonroad diesel engines.
Industry	333111	3523	Manufacturers of farm machinery and equipment.
Industry	333112	3524	Manufacturers of lawn and garden tractors (home).
Industry	333924	3537	Manufacturers of industrial trucks.
Industry	333120	3531	Manufacturers of construction machinery.

Category	NAICS codes[a]	SIC codes[b]	Examples of potentially regulated entities
Industry	333131	3532	Manufacturers of mining machinery and equipment.
Industry	333132	3533	Manufacturers of oil and gas field machinery and equipment.
Industry	811112	7533	Commercial importers of vehicles and vehicle components.
	811198	7549	
Industry	324110	2911	Petroleum refiners.
Industry	422710	5171	Diesel fuel marketers and distributors.
	422720	5172	
Industry	484220	4212	Diesel fuel carriers.
	484230	4213	

Notes:
[a] North American Industry Classification System (NAICS).
[b] Standard Industrial Classification (SIC) system code.

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

Docket. EPA has established an official public docket for this action under Docket ID No. OAR–2003–0012 at *http://www.epa.gov/edocket.* 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 Reading Room is (202) 566–1742, and the telephone number for the Air Docket is (202) 566–1742.

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 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. 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. Once in the system, select "search," then key in the appropriate docket identification number.

Outline of This Preamble

I. Overview

EPA today is completing the third recent major program to reduce emissions from the nation's mobile sources. Today's final rule establishes standards for nonroad diesel engines and fuel and builds on the recently adopted Tier 2 program for cars and light trucks and the 2007 highway diesel program for on-highway diesel engines. These three programs have in common large reductions in sulfur levels in fuel that will not only achieve public health benefits but also facilitate the introduction of advanced emissions control technologies. In 1996, emissions from land-based nonroad, marine, and locomotive diesel engines were estimated to be about 40 percent of the total mobile source inventory of $PM_{2.5}$ (particulate matter less than 2.5 microns in diameter) and 25 percent of the NO_X (nitrogen oxides) inventory. Without today's final rule, these contributions would be expected to grow to 44 percent and 47 percent by 2030 for $PM_{2.5}$ and NO_X, respectively. By themselves, land-based nonroad diesel engines are a very large part of the diesel mobile source $PM_{2.5}$ inventory, contributing about 47 percent in 1996, and growing to 70 percent of this inventory by 2020 without today's final rule. In order to meet the Clean Air Act's goal of cleaning up the nation's air, emissions reductions from the nonroad sector are necessary.

This program begins to get important emission reductions in 2008, and by 2030 we estimate that this program will reduce over 129,000 tons $PM_{2.5}$ and 738,000 tons of NO_X annually. These emission reductions will be directly helpful to the 474 counties nationwide that have been recently designated as nonattainment areas for the 8-hour ozone standard and for counties that will be designated as nonattainment for $PM_{2.5}$ later this year. The resulting ambient $PM_{2.5}$ and NO_X reductions correspond to public health improvements in 2030 including approximately 12,000 fewer premature mortalities, 15,000 fewer heart attacks, 1 million fewer lost days of work due to adults with respiratory symptoms, 5.9 million fewer days when adults have to restrict their activities due to respiratory symptoms, and almost 6,000 emergency room visits for asthma attacks in children. Our projections in this final rule for public health and welfare improvements are greater than estimated at proposal.

This final rule sets out emission standards for nonroad diesel engines—engines used mainly in construction, agricultural, industrial and mining operations—that will achieve reductions in PM and NO_X emissions levels in excess of 95 percent and 90 percent respectively. This action also regulates nonroad diesel fuel for the first time by reducing sulfur levels in this fuel more than 99 percent to 15 parts per million (ppm). These provisions mirror those already in place for highway diesel engines, which will lead to the introduction of 15 ppm sulfur diesel fuel, followed by stringent engine standards in that sector beginning in 2007 based on advanced aftertreatment technologies. We believe it is highly appropriate to bring the same types of expected advanced aftertreatment technologies to the nonroad market as soon as possible and we believe today's nonroad fuel and engine program represents the next step in a feasible progression in the application of clean technologies to nonroad diesel engines and the associated diesel fuel.

As we did with the proposed nonroad rulemaking, we followed specific principles when developing this final rule. First, the program achieves reductions in NO_X, sulfur oxides (SO_X), and PM emissions as early as possible. Second, it does so by implementing the fuel program as soon as possible while at the same time not interfering with the implementation and expected benefits of introducing ultra low sulfur fuel (diesel fuel containing no greater than 15 ppm sulfur) in the highway market as required by the 2007 highway diesel rule. Next, we are generally treating vehicles and fuels as a system, that is promulgating engine and fuel standards in tandem in order to cost-effectively achieve the greatest emission reductions. Lastly, the program provides sufficient lead time to allow the migration of advanced emissions control technologies from the highway sector to nonroad diesel engines as well as the expansion of ultra low sulfur diesel fuel production to the nonroad market.

The May 2003 proposed rulemaking culminated a multi-year effort to develop control strategies for nonroad engines. EPA worked collaboratively with stakeholders from industry, state and local government, and public health organizations in putting together its comprehensive (and widely praised) new engine standards and sulfur fuel controls. We received about 150,000 comments on the proposal, almost all of them in support. We held three public hearings on the proposal and have participated in scores of meetings with commenters in developing the provisions of today's final rule. An important aspect of this collaborative development effort has been EPA's coordination with other governments in helping to further world harmonization of nonroad engine controls and fuel sulfur levels. Information gathered in these comments and discussions, taken in context with the principles described above, has been the basis for our action today.

In summary, this rule sets out engine standards and emission test procedures (including not-to-exceed requirements) for new nonroad diesel engines, and sulfur control requirements for diesel fuel used in land-based nonroad, locomotive, and marine engines (NRLM fuel). Beginning in 2008, the new Tier 4 engine standards for five power categories for engines from under 25 horsepower (hp) to above 750 horsepower will be phased in. New engine emissions test procedures will be phased in along with these new standards to better ensure emissions control over real-world engine operation and to help provide for effective compliance determination. The sulfur reductions to land-based nonroad diesel fuel will be accomplished in two steps, with an interim step from currently uncontrolled levels to a 500 ppm cap starting in June, 2007 and the final step to 15 ppm in June, 2010. This change in fuel quality will directly lead to important health and welfare benefits associated with the reduced generation of sulfate PM and SO_X. Even more important, introduction of 15 ppm sulfur nonroad diesel fuel facilitates the introduction of advanced aftertreatment devices for nonroad engines.

Although we did not propose to control locomotive and marine diesel fuel sulfur levels to 15 ppm in the NPRM, recognizing the important environmental and public welfare benefits that such a program could enable, we have decided to finalize this second step to 15 ppm sulfur fuel control program for locomotive and marine diesel fuel beginning in 2012. Locomotive and marine diesel fuel will first be reduced from current uncontrolled levels to a 500 ppm cap starting in June 2007 and the second step down to a 15 ppm cap will take place in June, 2012. While we have chosen to reduce sulfur levels in locomotive and marine diesel fuel to 15 ppm in this rulemaking without adopting corresponding engine controls, we note that the Agency has already begun work to promulgate appropriate new standards for these engines.[1] The monetized health and welfare benefits associated with further sulfur reduction to 15 ppm outweigh the costs of the sulfur reductions. Also, doing so now allows for the promulgation of a single integrated fuel program and provides the refining industry with long term predictability for sulfur control.

The requirements in this rule will result in substantial benefits to public health and welfare and the environment through significant reductions in NO_X and PM as well as nonmethane hydrocarbons (NMHC), carbon monoxide (CO), SO_X, and air toxics. As noted, by 2030 this program will reduce annual emissions of NO_X and PM by 738,000 and 129,000 tons, respectively. We estimate these annual emission reductions will prevent 12,000 premature deaths, over 8,900 hospitalizations, 15,000 nonfatal heart attacks, and approximately 1 million days that people miss work because of respiratory symptoms, among quantifiable benefits. The overall quantifiable benefits will total $83 billion annually by 2030 using a 3 percent discount rate and $78 billion using a 7 percent discount rate at a cost of approximately $2 billion, with a 30-year net present value for the benefits of $805 billion at 3 percent discounting and $352 billion at 7 percent discounting at a net present value cost of $27 billion at 3 percent discounting and $14 billion at 7 percent discounting. Clearly the benefits of this program dramatically outweigh its cost at a ratio of approximately 40:1 in 2030.

A. What Is EPA Finalizing?

As part of the proposed rulemaking, we set out very detailed provisions for new engine exhaust emission controls, sulfur limitations in nonroad and locomotive/marine diesel fuels, test procedures, compliance requirements, and other information. We also looked at a number of alternative program options, such as requiring refiners to reduce sulfur from uncontrolled levels to 15 ppm in one step in 2008. We continue to believe that the main program options set out in the proposal are feasible and the most cost-effective requirements, taking into account other factors such as lead time and interaction with the highway diesel program, so we are generally adopting the engine and fuel provisions which we proposed.

1. Nonroad Diesel Engine Emission Standards

Today's action adopts Tier 4 standards for nonroad diesel engines of all horsepower ratings. These standards are technology-neutral in the sense that manufacturers are the responsible party in determining which emission control technologies will be needed to meet the requirements. Applicable emissions standards are determined by model year for each of five engine power band categories. For engines less than 25 hp, we are adopting a new engine standard for PM of 0.30 g/bhp-hr (grams per brake-horsepower-hour) beginning in 2008, and leaving the previously-set 5.6 g/bhp-hr combined standard for NMHC+NO_X in place. For engines of 25 to 75 hp, we are adopting standards reflecting approximately 50 percent reductions in PM control from today's engines, again applicable beginning in 2008. Then, starting in 2013, standards of 0.02 g/bhp-hr for PM and 3.5 g/bhp-hr for NMHC+NO_X will apply for this power category. For engines of 75 to 175 hp, the standards will be 0.01 g/bhp-hr for PM, 0.30 g/bhp-hr for NO_X and 0.14 g/bhp-hr for NMHC starting in 2012, with the NO_X and NMHC standards phased in over a period of three to four years in order to address lead time, workload, and feasibility considerations. These same standards will apply to engines of 175 to 750 hp as well starting in 2011, with a similar phase-in. These PM, NO_X, and NMHC standards and phase-in schedules are similar in stringency to the 2007 highway diesel standards and are expected to require the use of high-efficiency aftertreatment systems to ensure compliance.

For engines above 750 hp, we are requiring PM and NMHC control to 0.075 g/bhp-hr and 0.30 g/bhp-hr, respectively, starting in 2011. More stringent standards take effect in 2015 with PM standards of 0.02 g/bhp-hr (for engines used in generator sets) and 0.03 g/bhp-hr (for non-generator set engines), and an NMHC standard of 0.14 g/bhp-hr. The NO_X standard in 2011 will be 0.50 g/bhp-hr for generator set engines above 1200 hp, and 2.6 g/bhp-hr for all other engines in the above 750 hp category. This application of advanced NO_X emission control technologies to generator set engines above 1200 hp will provide substantial NO_X reductions and will occur earlier than we had proposed in the NPRM. In 2015, the 750–1200 hp generator set engines will be added to the stringent 0.50 g/bhp-hr NO_X requirement as well. The long-term NO_X standard for engines not used in generator sets (mobile machinery) will be addressed in a future action (we are currently considering such an action in the 2007 time frame).

We are also continuing the averaging, banking, and trading provisions engine manufacturers can use to demonstrate compliance with the standards. We also are continuing provisions providing flexibilities which equipment manufacturers may use to facilitate transition to compliance with the new standards. In addition, we are including turbocharged diesels in the existing regulation of crankcase emissions, effective in the same year that the new standards first apply in each power category.

As discussed at length in the proposal, new test procedures and compliance provisions, especially the not-to-exceed and transient tests, are necessary to ensure the benefits of the standards being adopted today are achieved when the aftertreatment-based standards go into place. We are therefore adopting the proposed test procedures and compliance provisions, with slight modifications designed to better implement the provisions, in today's rule. We continue to believe the new transient test, cold start transient test, and not-to-exceed test procedures and standards will all help achieve our goal of emissions reductions being achieved in actual engine operation.

As noted, the final rule also continues, and in some cases modifies, existing provisions that will facilitate the transition to the new engine and fuel standards. Many of these provisions will help small business engine and equipment manufacturers meet the requirements. They will also aid manufacturers in managing their development of engines and equipment that will meet our new standards.

2. Nonroad, Locomotive, and Marine Diesel Fuel Quality Standards

The fuel program requirements are very similar to those included in the proposal, with two notable exceptions. The first involves the standards themselves with the inclusion of locomotive and marine diesel fuel in the 15 ppm standard. The second addresses the compliance provisions designed to ensure the effectiveness of the program.

We are adopting the two-step approach to sulfur control, with all land-based nonroad, locomotive, and marine diesel fuel going from uncontrolled sulfur levels of approximately 3,000 ppm sulfur to 500 ppm in June, 2007. The interim step will by itself achieve significant PM and SO_X emission reductions with associated important health benefits as early as is practicable. Then, in June

[1] EPA is issuing an Advanced Notice of Proposed Rulemaking for locomotive and marine engine standards as part of this effort.

2010, the sulfur cap for land-based nonroad engine diesel fuel will be reduced to the final standard of 15 ppm. Two years later, in 2012, the 15-ppm cap for locomotive and marine engine diesel fuel will go into effect. The reduction to 15 ppm sulfur provides additional direct control of PM and SO_X emissions and is an enabling technology for the application of advanced catalyst-based emission control technologies.

Although we did not propose to control locomotive and marine diesel fuel to 15 ppm in the NPRM, after careful consideration and reviewing substantial comments from stakeholders, we have decided to include fuel used in locomotive and marine applications in the final step to 15 ppm beginning in 2012. The incremental PM health and welfare benefits associated with this standard outweigh the costs. The locomotive and marine diesel fuel program provides a near-term positive impact on public health and welfare. Also, the 15 ppm sulfur diesel fuel provides an opportunity that may enable the application of advanced catalyst-based emission control technologies to locomotive and marine diesel engines. We are issuing an Advance Notice of Proposed Rulemaking for locomotive and marine diesel engines that investigates this potential. Recognizing the value that a locomotive and marine fuel program could have for public health and welfare, State and local authorities and public health advocacy organizations provided a large number of comments encouraging us to take action in this rulemaking to address emissions from this category.

Including locomotive and marine fuel in the 15 ppm sulfur diesel fuel pool also simplifies the overall design of the fuel program and will simplify the distribution of diesel fuel. At the same time, we have finalized this standard with flexibilities designed specifically to address fuel program implementation issues raised in the comments.

Noting that sulfur levels in highway diesel fuel will generally be at or below 15 ppm starting in 2006 and not wanting to reduce the benefits of introducing this clean fuel, we spent considerable time developing a compliance assurance scheme for introducing our nonroad diesel sulfur program to mesh with the highway program requirements. We initially thought that a "baseline" approach essentially requiring refiners to maintain a constraint on sulfur levels of various distillate fuels, based on historical production volumes, was the most appropriate mechanism. Subsequently we learned that the other mechanism we discussed in the proposal, a "designate and track" type approach, is better suited to address our priorities and commitments for the nonroad diesel sulfur control program. This approach allows refiners to designate volumes of nonroad fuel into various categories and these designations would follow the fuel throughout the distribution system. We have successfully worked through our enforceability and other concerns with this approach and are now including it as our compliance mechanism for the fuel standards of today's program.

B. Why Is EPA Taking This Action?

As we have discussed extensively in both the proposal and today's action, EPA strongly believes it is appropriate to take steps now to reduce future emissions from nonroad, locomotive, and marine diesel engines. Emissions from these engines contribute greatly to a number of serious air pollution problems and would continue to do so in the future absent further reduction measures. Such emissions lead to adverse health and welfare effects associated with ozone, PM, NO_X, SO_X, and volatile organic compounds, including toxic compounds. In addition, diesel exhaust is of specific concern because it is likely to be carcinogenic to humans by inhalation as well as posing a hazard from noncancer respiratory effects. Ozone, NO_X, and PM also cause significant public welfare harm such as damage to crops, eutrophication, regional haze, and soiling of building materials.

Millions of Americans continue to live in areas with unhealthy air quality that may endanger public health and welfare. As discussed in more detail below, there are approximately 159 million people living in areas that either do not meet the 8-hour ozone National Ambient Air Quality Standards (NAAQS) or contribute to violations in other counties as noted in EPA's recent nonattainment designations for part or all of 474 counties. In addition, approximately 65 million people live in counties where air quality measurements violate the $PM_{2.5}$ NAAQS. These numbers do not include the tens of millions of people living in areas where there is a significant future risk of failing to maintain or achieve the ozone or $PM_{2.5}$ NAAQS. Federal, state, and local governments are working to bring ozone and PM levels into compliance with the NAAQS attainment and maintenance plans and the reductions included in today's rule will play a critical part in these actions. Reducing regional emissions of SO_X is critical to this strategy for attaining the PM NAAQS and meeting regional haze goals in our treasured national parks. SO_X levels can themselves pose a respiratory hazard.

Although controlling air pollution from nonroad diesel exhaust is challenging, we strongly believe it can be accomplished through the application of high-efficiency emissions control technologies. As discussed in much greater detail in section II, very large emission reductions (in excess of 90 percent) are possible, especially through the use of catalytic emission control devices installed in the nonroad equipment's exhaust system and integrated with the engine controls. To meet the standards being adopted today, application of such technologies for both PM and NO_X control will be needed for most engines. High-efficiency PM exhaust emission control technology has been available for several years, and it is the same technology we expect to be applied to meet the PM standards for highway diesel engines in 2007. For NO_X, we expect the same high-efficiency technologies being developed for the 2007 highway diesel engine program will be used to meet our new nonroad requirements. All of these technologies are dependent on the 15 ppm maximum sulfur levels for nonroad diesel fuel being adopted today. The fuel control program being adopted today also yields significant and important reductions in SO_X from these sources.

1. Basis for Action Under the Clean Air Act

Section 213 of the Clean Air Act ("the Act" or CAA) gives us the authority to establish emissions standards for nonroad engines and vehicles. Section 213(a)(3) authorizes the Administrator to set standards for NO_X, volatile organic compounds (VOCs), and CO which "standards shall achieve the greatest degree of emission reduction achievable through the application of technology which the Administrator determines will be available for the engines or vehicles." As part of this determination, the Administrator must give appropriate consideration to cost, lead time, noise, energy, and safety factors associated with the application of such technology. The standards adopted today for NO_X implement this provision. Section 213(a)(4) authorizes the Administrator to establish standards to control emissions of pollutants (other than those covered by section 213(a)(3)) which "may reasonably be anticipated to endanger public health and welfare." Here, the Administrator may promulgate regulations that are deemed appropriate for new nonroad vehicles and engines which cause or contribute to such air pollution, taking into account costs, noise, safety, and energy factors. EPA believes the new controls for PM in today's rule are an appropriate exercise of EPA's discretion under the authority of section 213(a)(4).

We believe the evidence provided in section II of this preamble and in the Regulatory Impact Analysis (RIA) indicates that the stringent emission standards adopted today are feasible and reflect the greatest degree of emission reduction achievable in the model years to which they apply. We have given appropriate consideration to costs in promulgating these standards. Our review of the costs and cost-effectiveness of these standards indicate that they will be reasonable and comparable to the cost-effectiveness of other emission reduction strategies for the same pollutants that have been required or could be required in the future. We have also reviewed and given appropriate consideration to the energy factors of this rule in terms of fuel efficiency and effects on diesel fuel supply, production, and distribution, as discussed below, as well as any safety factors associated with these new standards.

The information in this section and chapters 2 and 3 of the RIA regarding air quality and the contribution of nonroad, locomotive, and marine diesel engines to air pollution provides strong evidence that emissions from such engines significantly and adversely impact public health or welfare. First, as noted earlier, there is a significant risk that several areas will fail to attain or maintain compliance with the NAAQS for 8-hour ozone concentrations or the NAAQS for $PM_{2.5}$ during the period that these new vehicle and engine standards will be phased into the vehicle population, and that nonroad, locomotive, and marine diesel engines contribute to such concentrations, as well as to concentrations of other criteria pollutants. This risk will be significantly reduced by the standards adopted today, as also noted above. However, the evidence indicates that some risk remains even after the reductions achieved by these new controls on nonroad diesel engines and nonroad, locomotive, and marine diesel fuel. Second, EPA believes that diesel exhaust is likely to be carcinogenic to humans. The risk associated with exposure to diesel exhaust includes the particulate and gaseous components among which are benzene, formaldehyde, acetaldehyde, acrolein, and 1,3–butadiene, all of which are known or suspected human or animal carcinogens, or have noncancer health effects. Moreover, these compounds have the potential to cause health effects at environmental levels of exposure. Third, emissions from nonroad diesel engines (including locomotive and marine diesel engines) contribute to regional haze and impaired visibility across the nation, as well as to odor, acid deposition, polycyclic organic matter (POM) deposition, eutrophication and nitrification, all of which are serious environmental welfare problems.

EPA has already found in previous rules that emissions from new nonroad diesel engines contribute to ozone and CO concentrations in more than one area which has failed to attain the ozone and CO NAAQS (59 FR 31306, June 17, 1994). EPA has also previously determined that it is appropriate to establish standards for PM from new nonroad diesel engines under section 213(a)(4), and the additional information on diesel exhaust carcinogenicity noted above reinforces this finding. In addition, we have already found that emissions from nonroad engines significantly contribute to air pollution that may reasonably be anticipated to endanger public welfare due to regional haze and visibility impairment (67 FR 68242–68243, Nov. 8, 2002). We find here, based on the information in this section of the preamble and chapters 2 and 3 of the RIA, that emissions from the new nonroad diesel engines covered by this final action likewise contribute to regional haze and to visibility impairment that may reasonably be anticipated to endanger public welfare. Taken together, these findings indicate the appropriateness of the nonroad diesel engine standards adopted today for purposes of section 213(a)(3) and (4) of the Act. These findings were unchallenged by commenters.

These standards must take effect at "the earliest possible date considering the lead time necessary to permit development and application of the requisite technology," giving "appropriate consideration" to cost, energy, and safety.[2] The compliance dates we are adopting reflect careful consideration of these factors. The averaging, banking, and trading (ABT), equipment manufacturer flexibilities, and phase-in provisions for NO_X are elements in our determination that we have selected appropriate lead times for the standards.

Section 211(c) of the CAA allows us to regulate fuels where emission products of the fuel either: (1) Cause or contribute to air pollution that reasonably may be anticipated to endanger public health or welfare, or (2) will impair to a significant degree the performance of any emission control device or system which is in general use, or which the Administrator finds has been developed to a point where in a reasonable time it will be in general use were such a regulation to be promulgated. This rule meets both of these criteria. Sulfur dioxide (SO_2)and sulfate PM emissions from nonroad, locomotive, marine and diesel vehicles are due to sulfur in diesel fuel. As discussed above, emissions of these pollutants cause or contribute to ambient levels of air pollution that endanger public health and welfare. Control of sulfur to 15 ppm for this fuel through a two-step program would lead to significant, cost-effective reductions in emissions of these pollutants. Control of sulfur to 15 ppm in nonroad diesel fuel will also enable emissions control technology that will achieve significant, cost-effective reduction in emissions of these pollutants, as discussed in section I.B.2 below. The substantial adverse effect of high sulfur levels on the performance of diesel emission control devices or systems that would be expected to be used to meet the nonroad standards is discussed in detail in section II. Control of sulfur to 15 ppm for locomotive and marine diesel fuel, as with nonroad diesel fuel, will provide meaningful additional benefits that outweigh the costs. In addition, our authority under section 211(c) is discussed in more detail in Appendix A to chapter 5 of the RIA.

2. What Is the Air Quality Impact of This Final Rule?

a. Public Health and Environmental Impacts

With this rulemaking, we are acting to extend advanced emission controls to another major source of diesel engine emissions: Nonroad land-based diesel engines. This final rule sets out emission standards for nonroad land-based diesel engines—engines used mainly in construction, agricultural, industrial and mining operations—that will achieve reductions in PM and NO_X standards in excess of 95 percent and 90 percent, respectively for this class of vehicles. This action also regulates nonroad diesel fuel for the first time by reducing sulfur levels in this fuel more than 99 percent to 15 ppm. The diesel fuel sulfur requirements will decrease PM and SO_2 emissions for land-based diesel engines, as well as for three other nonroad source categories: Commercial marine diesel vessels, locomotives, and recreational marine diesel engines.

[2] See Clean Air Act section 213(b).

These sources are significant contributors to atmospheric pollution of (among other pollutants) PM, ozone and a variety of toxic air pollutants. In 1996, emissions from these four source categories were estimated to be 40 percent of the mobile source inventory for $PM_{2.5}$ and 25 percent for NO_X, and 10 percent and 13 percent of overall emissions for these potential health hazards, respectively. Without further controls beyond those we have already adopted, these sources will emit 44 percent of $PM_{2.5}$ from mobile sources and 47 percent of NO_X emissions from mobile sources by the year 2030.

Nonroad engines, and most importantly nonroad diesel engines, contribute significantly to ambient $PM_{2.5}$ levels, largely through direct emissions of carbonaceous and sulfate particles in the fine (and even ultrafine) size range. Nonroad diesels also currently emit high levels of NO_X which react in the atmosphere to form secondary $PM_{2.5}$ (namely ammonium nitrate) as well as ozone. Nonroad diesels also emit SO_2 and hydrocarbons which react in the atmosphere to form secondary $PM_{2.5}$ (namely sulfates and organic carbonaceous $PM_{2.5}$). This section summarizes key points regarding the nonroad diesel engine contribution to these pollutants and their impacts on human health and the environment. EPA notes that we are relying not only on the information presented in this preamble, but also on the more detailed information in chapters 2 and 3 of the RIA and technical support documents, as well as information in the preamble, RIA, and support documents for the proposed rule.

When fully implemented, this final rule will reduce nonroad (equipment such as construction, agricultural, and industrial), diesel $PM_{2.5}$ and NO_X emissions by 95 percent and 90 percent, respectively. It will also virtually eliminate nonroad diesel SO_2 emissions, which amounted to approximately 234,000 tons in 1996, and would otherwise grow to approximately 326,000 tons by 2020. These dramatic reductions in nonroad emissions are a critical part of the effort by federal, state and local governments to reduce the health related impacts of air pollution and to reach attainment of the NAAQS for PM and ozone, as well as to improve other environmental effects such as atmospheric visibility. Based on the most recent data available for this rule, such problems are widespread in the United States. There are almost 65 million people living in 120 counties with monitored $PM_{2.5}$ levels (2000–2002) exceeding the $PM_{2.5}$ NAAQS, and 159 million people living in areas recently designated as exceeding 8-hour ozone NAAQS. Figure I–1 illustrates the widespread nature of these problems. Shown in this figure are counties exceeding the $PM_{2.5}$ NAAQS or designated for nonattainment with the 8-hour ozone NAAQS plus mandatory Federal Class I areas, which have particular needs for reductions in atmospheric haze.

Our air quality modeling also indicates that similar conditions are likely to continue to persist in the future in the absence of additional controls and that the emission reductions would assist areas with attainment and future maintenance of the PM and ozone NAAQS.[3] For example, in 2020, based on emission controls currently adopted, we project that 66 million people will live in 79 counties with average $PM_{2.5}$ levels above 15 micrograms per cubic meter (ug/m^3). In 2030, the number of people projected to live in areas exceeding the $PM_{2.5}$ standard is expected to increase to 85 million in 107 counties. An additional 24 million people are projected to live in counties within 10 percent of the standard in 2020, which will increase to 64 million people in 2030. Furthermore, for ozone, in 2020, based on emission controls currently adopted, the number of counties violating the 8-hour ozone standard is expected to decrease to 30 counties where 43 million people are projected to live. Thereafter, exposure to unhealthy levels of ozone is expected to begin to increase again. In 2030 the number of counties violating the 8-hour ozone NAAQS is projected to increase to 32 counties where 47 million people are projected to live. In addition, in 2030, 82 counties where 44 million people are projected to live will be within 10 percent of violating the ozone 8-hour NAAQS.

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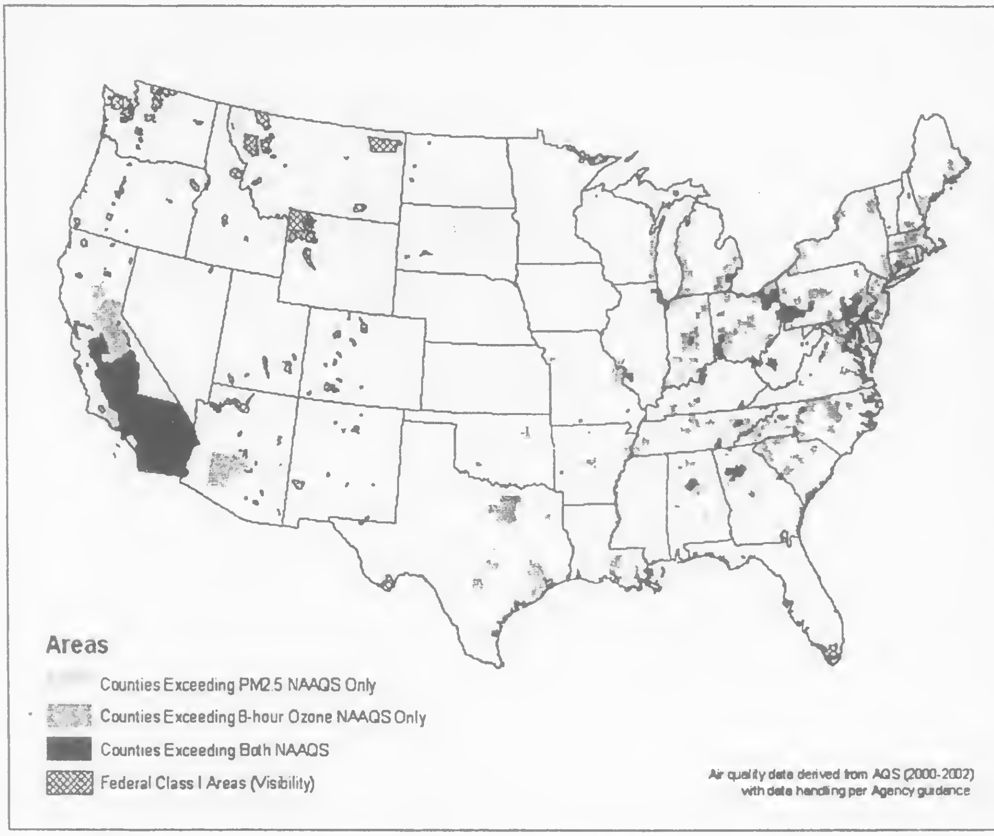
[3] Note this analysis does not include the effects of the proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule). 69 FR 4566 (January 30, 2004). *See http://www.epa.gov/interstateairquality/rule.html.*

Figure I-1. Air Quality Problems are Widespread



EPA is still developing the implementation process for bringing the nation's air into attainment with the $PM_{2.5}$ and 8-hour ozone NAAQS. Based on section 172(a) provisions in the Act, designated areas will need to attain the $PM_{2.5}$ NAAQS in the 2010 (based on 2007–2009 air quality data) to 2015 (based on 2012 to 2014 air quality data) time frame, and then be required to maintain the NAAQS thereafter. Similarly, we expect that most areas covered under subpart 1 and 2 will attain the ozone standard in the 2007 to 2014 time frame, depending on an area's classification and other factors, and then be required to maintain the NAAQS thereafter.

Since the emission reductions expected from this final rule would begin in this same time frame, the projected reductions in nonroad emissions would be used by states in meeting the $PM_{2.5}$ and ozone NAAQS. In their comments on the proposal, states told EPA that they need nonroad diesel engine reductions in order to be able to meet and maintain the $PM_{2.5}$ and ozone NAAQS as well as to make progress toward visibility requirements.[4] Furthermore, this action would ensure that nonroad diesel emissions will continue to decrease as the fleet turns over in the years beyond 2014; these reductions will be important for maintenance of the NAAQS following attainment.

Scientific studies show ambient PM is associated with a series of adverse health effects. These health effects are discussed in detail in the EPA Criteria Document for PM as well as the draft updates of this document released in the

[4] The following are sample comments from states and state associations on the proposed rule, which corroborate that this rule is a critical element in States' NAAQS attainment efforts. Fuller information can be found in the Summary and Analysis of Comments.

—"Unless emissions from nonroad diesels are sharply reduced, it is very likely that many areas of the country will be unable to attain and maintain health-based NAAQS for ozone and PM." (STAPPA/ALAPCO)

—"Adoption of the proposed regulation * * * is necessary for the protection of public health in California and to comply with air quality standards * * * The need for 15 ppm sulfur diesel fuel cannot be overstated." (California Air Resources Board)

—"The EPA's proposed regulation is necessary if the West is to make reasonable progress towards improving visibility in our nation's Class I areas." (Western Regional Air Partnership (WRAP))

—"Attainment of the NAAQS for ozone and $PM_{2.5}$ is of immediate concern to the states in the northeast region.* * * Thus, programs * * * such as the proposed rule for nonroad diesel engines are essential." (NESCAUM) past year.[5,6] EPA's "Health Assessment Document for Diesel Engine Exhaust," (the "Diesel HAD") also reviews health effects information related to diesel exhaust as a whole including diesel PM, which is one component of ambient PM.[7] In the Diesel HAD, we note that the particulate characteristics in the zone around nonroad diesel engines are likely to be substantially the same as published air quality measurements made along busy roadways. This conclusion supports the relevance of health effects associated with highway diesel engine-generated PM to nonroad applications.

As described in these documents, health effects associated with short-term variation in ambient PM have been indicated by epidemiologic studies showing associations between exposure and increased hospital admissions for ischemic heart disease, heart failure, respiratory disease, including chronic obstructive pulmonary disease (COPD) and pneumonia. Short-term elevations in ambient PM have also been associated with increased cough, lower respiratory symptoms, and decrements in lung function. Additional studies have associated changes in heart rate and/or heart rhythm in addition to changes in blood characteristics with exposure to ambient PM. Short-term variations in ambient PM have also been associated with increases in total and cardiorespiratory mortality. Studies examining populations exposed to different levels of air pollution over a number of years, including the Harvard Six Cities Study and the American Cancer Society Study, suggest an association between long-term exposure to ambient $PM_{2.5}$ and premature mortality, including deaths attributed to lung cancer.[8,9] Two studies further analyzing the Harvard Six Cities Study's air quality data have also established a specific influence of mobile source-related $PM_{2.5}$ on daily mortality and a concentration-response function for mobile source-associated $PM_{2.5}$ and daily mortality. Another recent study in 14 U.S. cities examining the effect of PM_{10} (particulate matter less than 10 microns in diameter) on daily hospital admissions for cardiovascular disease found that the effect of PM_{10} was significantly greater in areas with a larger proportion of PM_{10} coming from motor vehicles, indicating that PM_{10} from these sources may have a greater effect on the toxicity of ambient PM_{10} when compared with other sources.[10]

Of particular relevance to this rule is a recent cohort study which examined the association between mortality and residential proximity to major roads in the Netherlands. Examining a cohort of 55 to 69 year-olds from 1986 to 1994, the study indicated that long-term residence near major roads, an index of exposure to primary mobile source emissions (including diesel exhaust), was significantly associated with increased cardiopulmonary mortality.[11] Other studies have shown children living near roads with high truck traffic density have decreased lung function and greater prevalence of lower respiratory symptoms compared to children living on other roads.[12] A recent review of epidemiologic studies examining associations between asthma and roadway proximity concluded that some coherence was evident in the literature, indicating that asthma, lung function decrement, respiratory symptoms, and other respiratory problems appear to occur more frequently in people living near busy roads.[13] As discussed later, nonroad diesel engine emissions, especially particulate, are similar in composition to those from highway diesel vehicles. Although difficult to associate directly with $PM_{2.5}$, these studies indicate that direct emissions from mobile sources, and diesel engines specifically, may explain a portion of respiratory health effects observed in larger-scale epidemiologic studies. Recent studies conducted in Los Angeles have illustrated that a substantial increase in the concentration of ultrafine particles is evident in locations near roadways, indicating substantial differences in the nature of PM immediately near mobile source emissions.[14] For additional information on health effects, see the RIA.

In addition to its contribution to ambient PM concentrations, diesel exhaust is of specific concern because it has been judged to pose a lung cancer hazard for humans as well as a hazard from noncancer respiratory effects. In this context, diesel exhaust PM is generally used as a surrogate measure for diesel exhaust. Further, nonroad diesel engine emissions also contain several substances known or suspected as human or animal carcinogens, or that have noncancer health effects as described in the Diesel HAD. Moreover, these compounds have the potential to cause health effects at environmental levels of exposure. These other compounds include benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, dioxin, and POM. For some of these pollutants, nonroad diesel engine emissions are believed to account for a significant proportion of total nation-wide emissions. All of these compounds were identified as national or regional "risk drivers" in the 1996 NATA.[15] That is, these compounds pose a significant portion of the total inhalation cancer risk to a significant portion of the population. Mobile sources contribute significantly to total emissions of these air toxics. As discussed in more detail in the RIA, this final rulemaking will result in significant reductions of these emissions.

In EPA's Diesel HAD,[16] diesel exhaust was classified as likely to be carcinogenic to humans by inhalation at environmental exposures, in accordance with the revised draft 1996/1999 EPA cancer guidelines. A number of other agencies (National Institute for Occupational Safety and Health, the International Agency for Research on Cancer, the World Health Organization,

[5] U.S. EPA (1996.) Air Quality Criteria for Particulate Matter—Volumes I, II, and III, EPA, Office of Research and Development. Report No. EPA/600/P–95/001a–cF. This material is available electronically at *http://www.epa.gov/ttn/oarpg/ticd.html*.

[6] U.S. EPA (2003). Air Quality Criteria for Particulate Matter—Volumes I and II (Fourth External Review Draft) This material is available electronically at *http://cfpub.epa.gov/ncea/cfm/partmatt.cfm*.

[7] U.S. EPA (2002). Health Assessment Document for Diesel Engine Exhaust. EPA/600/8–90/057F Office of Research and Development, Washington, DC. This document is available electronically at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=29060*.

[8] Dockery, DW; Pope, CA, III; Xu, X; *et al.* (1993) An association between air pollution and mortality in six U.S. cities. N Engl J Med 329:1753–1759.

[9] Pope, CA, III; Burnett, RT; Calle, EE; *et al.* (2002) Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. JAMA 287: 1132–1141.

[10] Janssen, NA; Schwartz J; Zanobetti A; *et al.* (2002) Air conditioning and source-specific particles as modifiers of the effect of PM_{10} on hospital admissions for heart and lung disease. Environ Health Perspect 110(1):43–49.

[11] Hoek, G; Brunekreef, B; Goldbohm, S; *et al.* (2002) Association between mortality and indicators of traffic-related air pollution in the Netherlands: a cohort study. Lancet 360(9341):1203–1209.

[12] Brunekreef, B; Janssen NA; de Hartog, J; *et al.* (1997) Air pollution from traffic and lung function in children living near motor ways. Epidemiology (8): 298–303.

[13] Delfino RJ. (2002) Epidemiologic evidence for asthma and exposure to air toxics: linkages between occupational, indoor, and community air pollution research. Env Health Perspect Suppl 110(4): 573–589.

[14] Yifang Zhu, William C. Hinds, Seongheon Kim, Si Shen and Constantinos Sioutas Zhu Y; Hinds WC; Kim S; *et al.* (2002) Study of ultrafine particles near a major highway with heavy-duty diesel traffic. Atmos Environ 36(27): 4323–4335.

[15] U.S. EPA (2002). National-Scale Air Toxics Assessment. This material is available electronically at *http://www.epa.gov/ttn/atw/nata/*.

[16] U.S. EPA (2002). Health Assessment Document for Diesel Engine Exhaust. EPA/600/8–90/057F Office of Research and Development, Washington DC. This document is available electronically at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=29060*.

California EPA, and the U.S. Department of Health and Human Services) have made similar classifications.

EPA generally derives cancer unit risk estimates to calculate population risk more precisely from exposure to carcinogens. In the simplest terms, the cancer unit risk is the increased risk associated with average lifetime exposure of 1 ug/m^3. EPA concluded in the Diesel HAD that it is not possible currently to calculate a cancer unit risk for diesel exhaust due to a variety of factors that limit the current studies, such as lack of an adequate dose-response relationship between exposure and cancer incidence.

However, in the absence of a cancer unit risk, the EPA Diesel HAD sought to provide additional insight into the significance of the cancer hazard by estimating possible ranges of risk that might be present in the population. The possible risk range analysis was developed by comparing a typical environmental exposure level for highway diesel sources to a selected range of occupational exposure levels and then proportionally scaling the occupationally observed risks according to the exposure ratios to obtain an estimate of the possible environmental risk. A number of calculations are needed to accomplish this, and these can be seen in the EPA Diesel HAD. The outcome was that environmental risks from diesel exhaust exposure could range from a low of 10^{-4} to 10^{-5} or be as high as 10^{-3} this being a reflection of the range of occupational exposures that could be associated with the relative and absolute risk levels observed in the occupational studies. Because of uncertainties, the analysis acknowledged that the risks could be lower than 10^{-4} or 10^{-5} and a zero risk from diesel exhaust exposure was not ruled out. Although the above risk range is based on environmental exposure levels for highway mobile sources only, the 1996 NATA estimated exposure for nonroad diesel sources as well. Thus, the exposure estimates were somewhat higher than those used in the risk range analysis described above. The EPA Diesel HAD, therefore, stated that the NATA exposure estimates result in a similar risk perspective.

The ozone precursor reductions expected as a result of this rule are also important because of health and welfare effects associated with ozone, as described in the Air Quality Criteria Document for Ozone and Other Photochemical Oxidants. Ozone can irritate the respiratory system, causing coughing, throat irritation, and/or uncomfortable sensation in the chest.[17, 18] Ozone can reduce lung function and make it more difficult to breathe deeply, and 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/or the use of additional medication. In addition, ozone can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue, irreversible reductions in lung function, and a lower quality of life if the inflammation occurs repeatedly over a long time period (months, years, a lifetime). People who are of particular concern with respect to ozone exposures include children and adults who are active outdoors. Those people particularly susceptible to ozone effects are people with respiratory disease, such as asthma, and people with unusual sensitivity to ozone, and children. Beyond its human health effects, ozone has been shown to injure plants, which has the effect of reducing crop yields and reducing productivity in forest ecosystems.[19, 20]

New research suggests additional serious health effects beyond those that were known when the 8-hour ozone health standard was set. Since 1997, over 1,700 new health and welfare studies relating to ozone have been published in peer-reviewed journals.[21] Many of these studies investigate the impact of ozone exposure on such health effects as changes in lung structure and biochemistry, inflammation of the lungs, exacerbation and causation of asthma, respiratory illness-related school absence, hospital and emergency room visits for asthma and other respiratory causes, and premature mortality. EPA is currently evaluating these and other studies as part of the ongoing review of the air quality criteria and NAAQS for ozone. A revised Air Quality Criteria Document for Ozone and Other Photochemical Oxidants will be prepared in consultation with EPA's Clean Air Science Advisory Committee (CASAC). Key new health information falls into four general areas: Development of new-onset asthma, hospital admissions for young children, school absence rate, and premature mortality. In all, the new studies that have become available since the 8-hour ozone standard was adopted in 1997 continue to demonstrate the harmful effects of ozone on public health and the need for areas with high ozone levels to attain and maintain the NAAQS.

Finally, nonroad diesel emissions contribute to nine categories of non-health impacts: visibility impairment, soiling and material damage, acid deposition, eutrophication of water bodies, plant and ecosystem damage from ozone, water pollution resulting from deposition of toxic air pollutants with resulting effects on fish and wildlife, and odor. In particular, EPA determined that nonroad engines contribute significantly to unacceptable visibility conditions where people live, work and recreate, including contributing to visibility impairment in Federally mandated Class I areas that are given special emphasis in the Clean Air Act (67 FR 68242, November 8, 2002). Visibility is impaired by fine PM and precursor emissions from nonroad diesel engines subject to this final rule. Reductions in emissions from this final rule will improve visibility as well as other environmental outcomes as described in the RIA.

As supplementary information, we have made estimates using air quality modeling to illustrate the types of change in future $PM_{2.5}$ and ozone levels that we would expect to result from a final rule like this as described in chapter 2 of the RIA. That modeling shows that control of nonroad emissions would produce nationwide air quality improvements in $PM_{2.5}$ and ozone levels as well as visibility improvements. On a population-weighted basis, the average modeled change in future-year $PM_{2.5}$ annual averages is projected to decrease by 0.42 μg/m^3 (3.3%) in 2020, and 0.59 μg/m3 (0.6%) in 2030. In addition, the population-weighted average modeled change in future year design values for ozone would decrease by 1.8 parts per billion (ppb) in 2020, and 2.5 ppb in 2030. Within areas predicted to violate the ozone NAAQS in the projected base case, the average decrease would be somewhat higher: 1.9 ppb in 2020 and 3.0 ppb in 2030.

[17] U.S. EPA (1996). Air Quality Criteria for Ozone and Related Photochemical Oxidants, EPA/600/P–93/004aF. Docket No. A–99–06. Document Nos. II–A–15 to 17.

[18] U.S. EPA (1996). Review of National Ambient Air Quality Standards for Ozone, Assessment of Scientific and Technical Information, OAQPS Staff Paper, EPA–452/R–96–007. Docket No. A–99–06. Document No. II–A–22.

[19] U.S. EPA (1996). Air Quality Criteria for Ozone and Related Photochemical Oxidants, EPA/600/P–93/004aF. Docket No. A–99–06. Document Nos. II–A–15 to 17.

[20] U.S. EPA (1996). Review of National Ambient Air Quality Standards for Ozone, Assessment of Scientific and Technical Information, OAQPS Staff Paper, EPA–452/R–96–007. Docket No. A–99–06. Document No. II–A–22.

[21] New Ozone Health and Environmental Effects References, Published Since Completion of the Previous Ozone AQCD, National Center for Environmental Assessment, Office of Research and Development, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711 (7/2002) Docket No. A–2001–28, Document II–A–79.

The PM air quality improvements expected from this final rule are anticipated to produce major benefits to human health and welfare, with a combined value in excess of half a trillion dollars between 2007 and 2030. For example, in 2030, we estimate that this program will reduce approximately 129,000 tons $PM_{2.5}$ and 738,000 tons of NO_X. The resulting ambient PM reductions correspond to public health improvements in 2030, including 12,000 fewer premature mortalities, 15,000 fewer heart attacks, 200,000 fewer asthma exacerbations in children, and 1 million fewer days when adults miss work due to their respiratory symptoms, and 5.9 million fewer days when adults have to restrict their activities due to respiratory symptoms. The reductions will also improve visibility and reduce diesel odor. For further details on the economic benefits of this rule, please refer to the benefit-cost discussion in section VI of this preamble and chapter 9 of the RIA.

b. Emissions From Nonroad Diesel Engines

The engine and fuel standards in this final rule will affect emissions of direct $PM_{2.5}$, SO_2, NO_X, VOCs, and air toxics for land-based nonroad diesel engines.[22] For locomotive, commercial marine vessel (CMV), and recreational marine vessel (RMV) engines, the final fuel standards will affect direct $PM_{2.5}$ and SO_2 emissions. Each sub-section below discusses one of these pollutants,[23] including expected emission reductions associated with the final standards.[24] Table I.B–1 summarizes the impacts of this rule for 2020 and 2030. Further details on our inventory estimates, including results for other years, are available in chapter 3 of the RIA.

TABLE I.B–1.—ESTIMATED NATIONAL (50 STATE) REDUCTIONS IN EMISSIONS FROM NONROAD LAND-BASED, LOCOMOTIVE, COMMERCIAL MARINE, AND RECREATIONAL MARINE DIESEL ENGINES

Pollutant [short tons]	2020	2030
Direct $PM_{2.5}$:		
$PM_{2.5}$ Emissions Without Rule	167,000	181,000
$PM_{2.5}$ Emissions With 500 ppm Sulfur in 2007 and No Other Controls	144,000	155,000
$PM_{2.5}$ Emissions With 15 ppm Sulfur in 2012 and No Other Controls	141,000	152,000
$PM_{2.5}$ Emissions With Entire Rule	81,000	52,000
$PM_{2.5}$ Reductions Resulting from this Rule	86,000	129,000
SO_2:		
SO_2 Emissions Without Rule	326,000	379,000
SO_2 Emisions With 500 ppm Sulfur in 2007	37,000	43,000
SO_2 Emissions With Entire Rule (15 ppm Sulfur in 2012)	3,000	3,000
SO_2 Reductions Resulting from this Rule	323,000	376,000
NO_X—Land-Based Nonroad Engines Only[a]:		
NO_X Emissions Without Rule	1,125,000	1,199,000
NO_X Emissions With Rule	681,000	461,000
NO_X Reductions Resulting from this Rule	444,000	738,000
VOC—Land-Based Nonroad Engines Only[a]:		
VOC Emissions Without Rule	98,000	97,000
VOC Emissions With Rule	75,000	63,000
VOC Reductions Resulting from this Rule	23,000	34,000

Notes:
[a] NO_X and VOC numbers only include emissions for land-based nonroad diesel engines because the Tier 4 controls will not be applied to locomotive, commercial marine, and recreational marine engines; and no NO_X and VOC emission reductions are generated through the lowering of fuel sulfur levels.

i. Direct $PM_{2.5}$

As described earlier, the Agency believes that reductions of diesel $PM_{2.5}$ emissions are needed as part of the nation's progress toward clean air. Direct $PM_{2.5}$ emissions from land-based nonroad diesel engines amount to increasingly large percentages of total man-made diesel $PM_{2.5}$. Between 1996 and 2030, we estimate that the percentage of total man-made diesel $PM_{2.5}$ emissions coming from land-based nonroad diesel engines will increase from about 46 percent to 72 percent (based on a 48 state inventory).

Emissions of direct $PM_{2.5}$ from land-based nonroad diesel engines based on a 50 state inventory are shown in table I.B–1, along with our estimates of the reductions in 2020 and 2030 we expect would result from our final rule for a $PM_{2.5}$ exhaust emission standard and from changes in the sulfur level in land-based nonroad, locomotive, and marine diesel fuel. Land-based nonroad, locomotive, and marine diesel fuel sulfur levels will be lowered to about 340 ppm in-use (500 ppm maximum) in 2007. Land-based nonroad diesel fuel sulfur will be lowered further to about 11 ppm in-use (15 ppm maximum) in 2010 and locomotive and marine diesel fuel sulfur will be lowered to the same level in 2012. In addition to $PM_{2.5}$ emissions estimates with the final rule, emissions estimates based on lowering diesel fuel sulfur without any other controls are shown in table I.B–1 for 2020 and 2030.

Figure I.B–1a shows our estimate of $PM_{2.5}$ emissions between 2000 and 2030 both without and with the final standards and fuel sulfur requirements of this rule. We estimate that $PM_{2.5}$ emissions from this source would be reduced by 71 percent in 2030.

ii. SO_2

We estimate that land-based nonroad, CMV, RMV, and locomotive diesel engines emitted about 234,000 tons of

[22] We are also adopting a few minor adjustments of a technical nature to current CO standards. Emissions effects from these standards are discussed in the RIA.

[23] The estimates of baseline emissions and emissions reductions from the final rule reported here for nonroad land-based, recreational marine, locomotive, and commercial marine vessel diesel engines are based on 50 state emissions inventory estimates. A 48 state inventory was used for air quality modeling that EPA conducted for this rule, of which Alaska and Hawaii are not a part. In cases where land-based nonroad diesel engine emissions are compared with non-mobile source portions of the inventory, we use a 48 state emissions inventory, to match the 48 state nature of those other inventories.

[24] Please see the Summary and Analyses of Comments document for discussions of issues raised about the emission inventory estimates during the comment period for the NPRM.

SO_2 in 1996, accounting for about 33 percent of the SO_2 from mobile sources (based on a 48 state inventory). With no reduction in diesel fuel sulfur levels, we estimate that these emissions will continue to increase, accounting for about 44 percent of mobile source SO_2 emissions by 2030.

As part of this final rule, sulfur levels in fuel will be significantly reduced, leading to large reductions in nonroad, locomotive, and marine diesel SO_2 emissions. By 2007, the sulfur in diesel fuel used by all land-based nonroad, locomotive, and marine diesel engines will be reduced from the current average in-use level of between 2,300 to 2,400 ppm [25] to an average in-use level of about 340 ppm, with a maximum level of 500 ppm. By 2010, the sulfur in diesel fuel used by land-based nonroad engines will be reduced to an average in-use level of 11 ppm with a maximum level of 15 ppm. Sulfur in diesel fuel used by locomotive and marine engines will be reduced to the same level by 2012. Table II.B–1 and figure II.B–1b show the estimated reductions from these sulfur changes.

[25] Highway fuel is currently used in a significant fraction of land based nonroad equipment, locomotives, and marine vessels, reducing the in-use average sulfur level from about 3,000 ppm for uncontrolled high-sulfur fuel to 2,300 or 2,400 ppm.

iii. NO_X

Table I.B–1 shows the 50 state estimated tonnage of NO_X emissions for 2020 and 2030 without the final rule and the estimated tonnage of emissions eliminated with the final rule in place. These results are shown graphically in Figure I.E–1c at the end of this section. We estimate that NO_X emissions from these engines will be reduced by 62 percent in 2030.

We note that the magnitude of NO_X reductions determined in the final rule analysis is somewhat less than what was reported in the proposal's preamble and RIA, especially in the later years when the fleet has mostly turned over to Tier 4 designs. The greater part of this is due to the fact that we have deferred setting a long-term NO_X standard for mobile machinery over 750 horsepower to a later action. When this future action is completed, we would expect roughly equivalent reductions between the proposal and the overall final program, though there are some other effects reflected in the differing NO_X reductions as well, due to updated modeling assumptions and the adjusted NO_X standards levels for engines over 750 horsepower. Section II.A.4 of this preamble contains a detailed discussion of the NO_X standards we are adopting for engines over 750 horsepower as well as the basis for those standards.

iv. VOCs and Air Toxics

Based on a 48 state emissions inventory, we estimate that land-based nonroad diesel engines emitted over 221 thousand tons of VOC in 1996. Between 1996 and 2030, we estimate that land-based nonroad diesel engines will contribute about 2 to 3 percent of mobile source VOC emissions. Without further controls, land-based nonroad diesel engines will emit about 97 thousand tons/year of VOC in 2020 and 2030 nationally.

Table I.B–1 shows our projection of the reductions in 2020 and 2030 for VOC emissions that we expect from implementing the final NMHC standards. This estimate is based on a 50 state emissions inventory. By 2030, VOC emissions from this category would be reduced by 35 percent from baseline levels.

While we are not adopting any specific gaseous air toxics standards in today's rule, air toxics emissions would nonetheless be significantly reduced through the NMHC standards included in the final rule. By 2030, we estimate that emissions of air toxics pollutants, such as benzene, formaldehyde, acetaldehyde, 1,3-butadiene, and acrolein, would be reduced by 35 percent from land-based nonroad diesel engines. Diesel PM reductions were discussed above. For specific air toxics reduction estimates, see chapter 3 of the RIA.

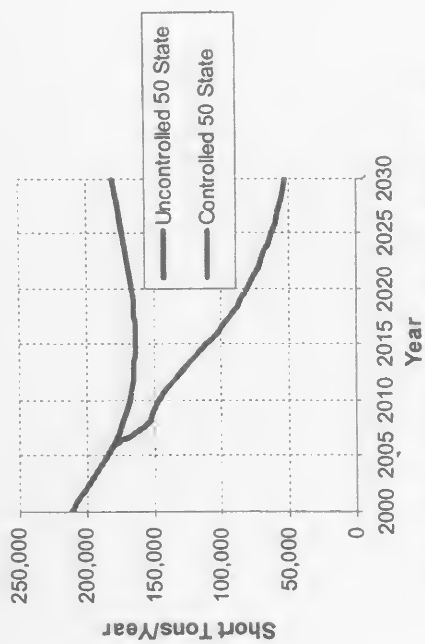


Figure I.B-1a: Estimated $PM_{2.5}$ Reductions From Nonroad Land-Based Diesel Engine Standard and Diesel Fuel Sulfur Reductions

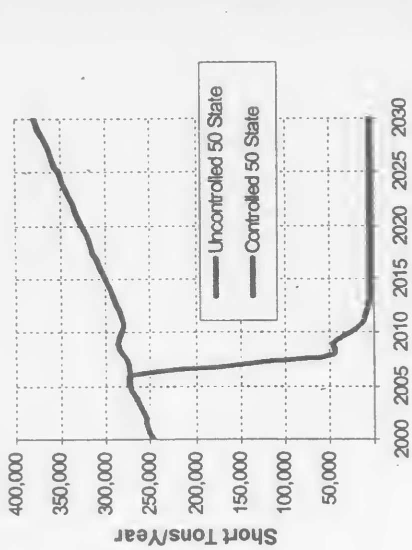


Figure I.B-1b: Estimated SO_2 Reductions From Lowering Diesel Fuel Sulfur For Land-Based Nonroad Engines, CMVs, RMVs, and Locomotives

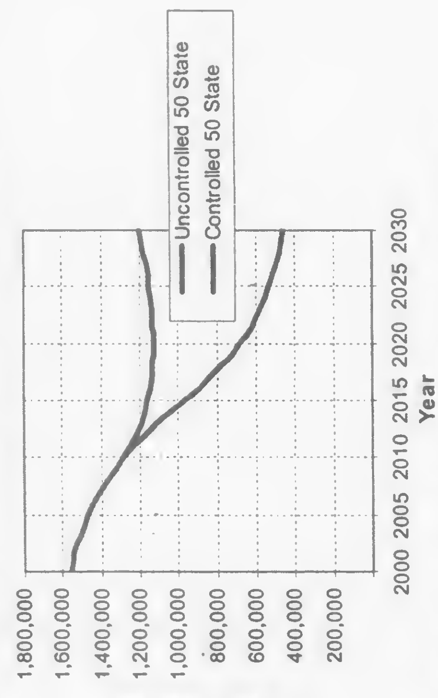


Figure I.B-1c: Estimated NOx Reductions From Land-Based Nonroad Diesel Engine Standard

II. Nonroad Engine Standards

In this section we describe the emission standards for nonroad diesel engines that we are setting to address the serious air quality problems discussed in section I. These Tier 4 standards, which take effect starting in 2008, are very similar to those proposed, and obtain very similar emissions reductions. The long-term PM filter-based standards that apply to all engines over 25 hp, combined with the fuel change and new requirements to ensure robust control in the field, will yield PM reductions of over 95% from the in-use levels of today's cleanest Tier 2 engines. Likewise, the long-term NO_X standards we are adopting for nearly all engines above 75 hp will yield NO_X reductions of about 90% from the NO_X levels expected from even the low-emitting Tier 3 engines due to first reach the market in 2006 or later. The Tier 4 standards will bring about large reductions in toxic hydrocarbon emissions as well.

In this final rule we are largely adopting the standards and timing we proposed, with the exception of those that apply to engines over 750 hp. We restructured and modified the standards and timing for these engines to address technical concerns and to focus on achieving comparable emission reductions through the introduction of advanced technology as early as feasible from specific applications within this power category. See section II.A.4 for a detailed discussion. We also are not adopting the proposed minor adjustments to the CO standard levels for some engines under 75 hp, as explained in section II.A.6. In addition, there are minor changes from the proposal in the phase-in approach we are adopting for NO_X and NMHC standards, as detailed in this section.

In this section we discuss:

• The Tier 4 engine standards, and the schedule for implementing them;

• The feasibility of the Tier 4 standards (in conjunction with the low-sulfur nonroad diesel fuel requirement discussed in section IV); and

• How diesel fuel sulfur affects an engine's ability to meet the new standards.

Additional provisions for engine and equipment manufacturers are discussed in detail in section III. These include:

• The averaging, banking, and trading (ABT) program.

• The transition program for equipment manufacturers.

• The addition of a "not-to-exceed" program to ensure in-use emissions control. This program includes new emission standards and related test procedures to supplement the standards discussed in this section.

• The test procedures and other compliance requirements associated with the emission standards.

• Special provisions to aid small businesses in implementing our requirements.

• An incentive program to encourage innovative technologies and the early introduction of new technologies.

A. What Are the New Engine Standards?

The Tier 4 exhaust emissions standards for PM, NO_X, and NMHC are summarized in tables II.A–1, 2, and 4.[26] Crankcase emissions control requirements are discussed in section II.A.7. Previously adopted CO emission standards continue to apply as well. All of these standards apply to covered nonroad engines over the useful life periods specified in our regulations, except where temporary in-use compliance margins apply as discussed in section III.E. To help ensure that these emission reductions will be achieved in use, we have adopted test procedures for measuring compliance with these standards tailored to both steady-state and transient nonroad engine operating characteristics. These test procedures are discussed in several subsections of section III. Another component of our program to ensure control of emissions in-use is the new "not-to-exceed" (NTE) emission standards and associated test procedures, discussed in section III.J.

TABLE II.A–1.—TIER 4 PM STANDARDS (G/BHP-HR) AND SCHEDULE

Engine power	Model year					
	2008	2009	2010	2011	2012	2013
hp < 25 (kW < 19)	[a] 0.30	....	....	....	....	....
25 ≤ hp < 75 (19 ≤ kW < 56)	[b] 0.22	....	....	....	....	0.02
75 ≤ hp < 175 (56 ≤ kW < 130)	....	....	....	....	0.01	....
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	....	....	....	0.01	....	....
hp 750 (kW > 560)	See table II.A–4					

Notes:
[a] For air-cooled, hand-startable, direct injection engines under 11 hp, a manufacturer may instead delay implementation until 2010 and demonstrate compliance with a less stringent PM standard of 0.45 g/bhp-hr, subject also to additional provisions discussed in section II.A.3.a.
[b] A manufacturer has the option of skipping the 0.22 g/bhp-hr PM standard for all 50–75 hp engines. The 0.02 g/bhp-hr PM standard would then take effect one year earlier for all 50–75 hp engines, in 2012.

TABLE II.A–2.—TIER 4 NO_X AND NMHC STANDARDS AND SCHEDULE

Engine power	Standard (g/bhp-hr)		Phase-in schedule (model year) (percent)			
	NO_X	NMHC	2011	2012	2013	2014
25 ≤ hp < 75 (19 ≤ kW < 56)	3.5 NMHC+NO_X [a]		....	....	100%	....
75 ≤ hp < 175 (56 ≤ kW < 130)	0.30	0.14	[b] 50	[b] 50	[b] 100	
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	0.30	0.14	50	50	50	100
hp > 750 (kW > 560)	See table II.A–4					

Notes: Percentages indicate production required to comply with the Tier 4 standards in the indicated model year.
[a] This is the existing Tier 3 combined NMHC+NO_X standard level for the 50–75 hp engines in this category. In 2013 it applies to the 25–50 hp engines as well.
[b] Manufacturers may use banked Tier 2 NMHC+NO_X credits from engines at or above 50 hp to demonstrate compliance with the 75–175 hp engine NO_X standard in this model year. Alternatively, manufacturers may forego this special banked credit option and instead meet an alternative phase-in requirement of 25/25/25% in 2012, 2013, and 2014 through December 30, with 100% compliance required beginning December 31, 2014. See sections III.A and II.A.2.b.

[26] Consistent with past EPA rulemakings for nonroad diesel engines, our regulations express standards, power ratings, and other quantities in international SI (metric) units—kilowatts, gram per kilowatt-hour, etc. This aids in achieving harmonization with standards-setting bodies outside the U.S., and in laboratory operations in which these units are the norm. However, in this preamble and in other rulemaking documents for the general reader, we have chosen to use terms more common in general usage in the U.S. Hence standards are expressed in units of grams per brake horsepower-hour, power ratings in horsepower, etc. In any compliance questions that might arise from differences in these due to, for example, rounding conventions, the regulations themselves establish the applicable requirements.

The long-term 0.01 and 0.02 g/bhp-hr Tier 4 PM standards for 75–750 hp and 25–75 hp engines, respectively, combined with the fuel change and new requirements to ensure robust control in the field, represent a reduction of over 95% from in-use levels expected with Tier 2/Tier 3 engines.[27] The 0.30 g/bhp-hr Tier 4 NO_X standard for 75–750 hp engines represents a NO_X reduction of about 90% from in-use levels expected with Tier 3 engines. Emissions reductions from engines over 750 hp are discussed in section II.A.4.

In general, there was widespread support in the comments for the proposed Tier 4 engine standards and for the timing we proposed for them. Some commenters raised category-specific concerns, especially for the smaller and the very large engine categories. These comments are discussed below.

1. Standards Timing

a. 2008 Standards

The timing of the Tier 4 engine standards is closely tied to the timing of fuel quality changes discussed in section IV, in keeping with the systems approach we are taking for this program. The earliest Tier 4 engine standards take effect in model year 2008, in conjunction with the introduction of 500 ppm maximum sulfur nonroad diesel fuel in mid-2007. This fuel change serves a dual environmental purpose. First, it provides a large immediate reduction in PM and SO_X emissions for the existing fleet of engines in the field. Second, its widespread availability by the end of 2007 aids engine designers in employing emissions controls capable of achieving the Tier 4 standards for model year 2008 and later engines; this is because the performance and durability of such technologies as exhaust gas recirculation (EGR) and diesel oxidation catalysts is improved by lower sulfur fuel.[28] The reduction of sulfur in nonroad diesel fuel will also provide sizeable economic benefits to machine operators as it will reduce wear and corrosion and will allow them to extend oil change intervals (see section VI.B). These economic benefits will occur for all diesel engines using the new fuel, not just for those built in 2008 or later.

As we proposed, these 2008 Tier 4 engine standards apply only to engines below 75 hp. We are not setting Tier 4 standards taking effect in 2008 for larger engines. The reasons for this differ depending on the engines' hp rating. Setting Tier 4 2008 standards for engines at or above 100 hp would provide an insufficient period of stability (an element of lead time) between Tier 2/3 and Tier 4, and so would not be appropriate. This is because these engines become subject to existing Tier 2 or 3 NMHC+NO_X standards in 2006 or 2007. Setting new 2008 standards for them thus would provide only one or two years of Tier 2/ Tier 3 stability before another round of design changes would have to be made in 2008 for Tier 4.

It is also inappropriate to establish 2008 Tier 4 standards for engines of 75–100 hp. The stability issue just noted for larger engines is not present for these engines, because these engines are subject to Tier 3 NMHC+NO_X standards starting in 2008, so that our setting a Tier 4 PM standard for them in the same year would not create the situation in which engines have to be redesigned twice to comply with new standards within a space of one or two years. However, EPA believes the more significant concern for these engines is meeting the stringent aftertreatment-based standards for PM and NO_X in 2012. We are concerned that adopting interim 2008 standards for these engines would divert resources needed to achieve these 2012 standards and indeed jeopardize attaining them. Thus, although early emission reductions from these engines in 2008 would of course be desirable, we felt that the focus we are putting on obtaining much larger reductions from them in 2012, together with the fact that we already have a Tier 3 NMHC+NO_X standard taking effect for 75–100 hp engines in 2008, warrants our not adding additional control requirements for these engines during this interim period.

We note that the 50–75 hp engines also have a Tier 3 NMHC+NO_X standard taking effect in 2008 and, as noted above, we are setting a new Tier 4 2008 PM standard for them. Unlike the larger 75–100 hp engines, however, the 50–75 hp engines have one additional year, until 2013, before filter-based PM standards take effect, and also have no additional NO_X control requirement being set beyond the 2008 Tier 3 standard. These differences justify including the interim Tier 4 PM standard for these engines. We note too that achieving the 2008 PM standard is enabled in part by the large reduction in certification fuel sulfur that applies in 2008 (see section III.D). Fuel sulfur has a known correlation to PM generation, even for engines without aftertreatment. Moreover, for any manufacturers who believe that accomplishing this PM pull-ahead will hamper their Tier 3 compliance efforts for these engines, there is an alternative Tier 4 compliance option. Instead of meeting new Tier 4 PM standards in both 2008 and 2013, manufacturers may skip the Tier 4 2008 PM standard, and instead focus design efforts on introducing PM filters for these engines one year earlier, by complying with the aftertreatment-based standard for PM in 2012. These options are discussed in more detail in section II.A.3.b.

We view the 2008 portion of the Tier 4 program as highly important because it provides substantial PM and SO_X emissions reductions during the several years prior to 2011. Initiating Tier 4 in 2008 also fits well with the lead time (including stability), cost, and technology availability considerations of the overall program. Initiating the Tier 4 engine standards in 2008 provides three to four years of stability after the start of Tier 2 for engines under 50 hp. As mentioned above, it also coincides with the start date of Tier 3 NMHC+NO_X standards for 50–75 hp engines and so introduces no stability issues for these engines (as redesign for both PM and NO_X occurs at the same time). The 2008 start date provides almost 4 years of lead time to accomplish redesign and testing. The evolutionary character of the 2008 standards, based as they are on proven technologies, and the fact that some certified engines already meet these standards as discussed in section II.B, leads us to conclude that the standards are appropriate within the meaning of section 213(a)(4) of the Clean Air Act and that we are providing adequate lead time to achieve those standards.

Engine and equipment manufacturers argued in their comments that the PM pull-ahead option for 50–75 hp engines is inappropriate because it constitutes a re-opening of the Tier 3 rule, involving as it does a Tier 4 PM standard in 2008, the same year that the Tier 3 NMHC+NO_X takes effect. They further argued that the non-pull-ahead option is not a real option because PM aftertreatment cannot be implemented for these engines in 2012.

We disagree with both contentions. We determined, as part of our feasibility analysis for Tier 4, that it is feasible to design engines to meet the 2008 PM standard in the same year that a Tier 3 NMHC+NO_X standard takes effect. See section II.B and RIA sections 4.1.4 and 4.1.5. One reason is that a substantial

[27] Note that we are grouping all standards in this rule, including those that take effect in 2008, under the general designation of "Tier 4 standards." As a result, there are no "Tier 3" standards in the multi-tier nonroad program for engines below 50 hp or above 750 hp.

[28] "Nonroad Diesel Emissions Standards Staff Technical Paper," EPA420–R–01–052, October 2001.

part of the 2008 PM emission reductions do not result from engine redesign, but rather are due to the reduction in certification test fuel maximum sulfur levels from 2000 to 500 ppm that results from the fuel change in the field. This reduction in sulfur levels also aids engine designers in employing emission control technologies that are detrimentally affected by sulfur, not only for PM control, but also for NMHC and NO_X control. Examples of these sulfur-sensitive technologies are oxidation catalysts, which can substantially reduce PM and NMHC, and EGR, which is effective at reducing NO_X. We note further that designing engines to meet the 2008 PM standard is also made less difficult by our not requiring engine designers to consider the transient test, cold start, and not-to-exceed requirements that are otherwise part of the Tier 4 program. These requirements do not take effect for these engines until the 0.02 g/bhp-hr standard is implemented in 2012 or 2013. See section III.F for details.

We also believe that the second option (compliance with the aftertreatment-based PM standard in 2012, with no interim 2008 standard) is viable, and may be an attractive choice especially for engine families on the higher side of the 50–75 hp range that share a design platform with larger engines being equipped with PM filters to meet the Tier 4 standard for 75–175 hp engines in 2012. We believe 75 hp is the appropriate cutpoint for setting and timing emissions standards (see section II.A.5), but it obviously is not a hard-and-fast separator between engine platforms for all manufacturers in all product lines. Even for many 50–75 hp engines that do not share a design platform with larger engines, we believe that a 2012 implementation date for PM filter technology may be practical, considering the 4-year lead time it affords after Tier 3 begins for these engines (in 2008), 8-year lead time after the last PM standard change (in 2004), and 5-year lead time after full-scale PM filter technology implementation on highway engines (in 2007).

Engine manufacturers also commented that the two-options approach would cause their customers to switch engine suppliers in 2012 to get the least expensive engines possible in every year, thus compromising the environmental objectives and creating market disruptions. We have addressed these concerns as discussed in section II.A.3.b.

b. 2011 and Later Standards

The second fuel change for nonroad diesel fuel, to 15 ppm maximum sulfur in mid-2010, and the related engine standards for PM, NO_X, and NMHC that begin to phase-in in the 2011 model year, provide most of the environmental benefits of the program. Like the 2008 standards, these standards are timed to provide adequate lead time for engine and equipment manufacturers. They also are phased in over time to allow for the orderly transfer of technology from the highway sector, and to spread the overall workload for engine and equipment manufacturers engaged in redesigning a large number and variety of products for Tier 4.

As we explained at proposal, we believe that the high-efficiency exhaust emission control technologies being developed to meet our 2007 emission standards for heavy-duty highway diesel engines can be adapted to most nonroad diesel applications. The engines for which we believe this adaptation from highway applications will be most straightforward are those in the 175–750 hp power range, and thus these engines are subject to new standards requiring high-efficiency exhaust emission controls as soon as the 15 ppm sulfur diesel fuel is widely available, that is, in the 2011 model year. Engines of 75–175 hp are subject to the new standards in the following model year, 2012, reflecting the need to spread the redesign workload and, to some extent, the greater effort that may be involved in adapting highway technologies to these engines. Engines between 25 and 75 hp are subject to new standards for PM based on high-efficiency exhaust emission controls in 2013, reflecting again the need to spread the workload and the challenge of adapting this technology to these engines which typically do not have highway counterparts. Engines over 750 hp involve a number of special considerations, necessitating an implementation approach unique to these engines as explained in section II.A.4. Lastly , there are additional provisions discussed in sections III.B.2 and III.M to encourage early technology introduction and to further draw from the highway technology experience.

This approach of implementing Tier 4 standards by power category over 2011–2013 provides for the orderly migration of technology and distribution of redesign workload over three model years, as EPA provided in Tier 3. Overall, this approach provides 4 to 6 years of real world experience with the new technology in the highway sector, involving millions of engines (in addition to the several additional years provided by demonstration fleets on the road in earlier years), before the new standards take effect. We consider the implementation of Tier 4 standard start dates over 2011–2013 as described above to be responsive to the technology migration and workload distribution concerns.

2. Phase-In of NO_X and NMHC Standards for 75–750 hp Engines

a. Percent-of-Production Phase-In for NO_X and NMHC

We are finalizing the percent-of-production phase-in for NO_X and NMHC that we proposed for 75–750 hp engines. Because Tier 4 NO_X emissions control technology is expected to be derived from technology first introduced in highway heavy-duty diesels, we proposed to adopt the implementation pattern for the Tier 4 NO_X standard which we adopted for the heavy-duty highway diesel program. This will help to ensure a focused, orderly development of robust high-efficiency NO_X control in the nonroad sector and will also help to ensure that manufacturers are able to take maximum advantage of the highway engine development program, with resulting cost savings.

The heavy-duty highway rule allows for a gradual phase-in of the NO_X and NMHC requirements over multiple model years: 50% of each manufacturer's U.S.-directed production volume must meet the new standard in 2007–2009, and 100% must do so by 2010. Through the use of emissions averaging, this phase-in approach also provides the flexibility for highway engine manufacturers to meet that program's environmental goals by allowing somewhat less-efficient NO_X controls on more than 50% of their production during the 2007–2009 phase-in years.

We follow the same pattern in this rule. As proposed, we are phasing in the NO_X standards for nonroad diesels over 2011–2013 as indicated in table II.A–2, based on compliance with the Tier 4 standards for 50% of a manufacturer's U.S.-directed production in each power category between 75 and 750 hp in each phase-in model year. The phase-in of standards for engines over 750 hp is discussed in section II.A.4. With a NO_X phase-in, all manufacturers are able to introduce their new technologies on a limited number of engines, thereby gaining valuable experience with the technology prior to implementing it on their entire product line. In tandem with the equipment manufacturer transition program discussed in section III.B, the phase-in ensures timely progress to the Tier 4 standard levels while providing a great degree of implementation flexibility for the industry.

This "percent of production phase-in" is intended to take maximum advantage of the highway program technology development. It adds a new dimension of implementation flexibility to the staggered "phase-in by power category" used in the nonroad program for Tiers 1–3 (and also in this Tier 4) which, though structured to facilitate technology development and transfer, is more aimed at spreading the redesign workload. Because the Tier 4 program involves challenges in addressing both technology development and redesign workload, we believe that incorporating both of these phase-in mechanisms into the program is warranted, resulting in the coordinated phase-in plan shown in table II.A–2, which we are finalizing essentially as proposed. Note that this results in the new NO_X requirements for 75–175 hp engines taking effect starting in the second year of the 2011–2013 general phase-in, in effect creating a 50–50% phase-in in 2012–2013 for this category. This then staggers the Tier 4 start years by power category as in past tiers: 2011 for engines at or above 175 hp, 2012 for 75–175 hp engines, and 2013 for 25–75 hp engines (for which no NO_X adsorber-based standard and thus no percentage phase-in is being adopted), while still providing a production-based phase-in for advanced NO_X control technologies.

Comments from the States and environmental organizations argued for the completion of the phase-in by the end of 2012, contending that technology progress for NO_X control in the highway sector has been good to date and would support an accelerated phase-in in the nonroad sector. However, our assessment continues to show unique (though surmountable) challenges in adapting advanced technologies to nonroad engines, especially for engines least like highway diesels, and it is these engines that would be most affected by a truncated phase-in schedule. Furthermore, even if we were to conclude that advanced technologies will be ready earlier than expected, we would not be able to move up the start of phase-in dates because these dates also depend on low-sulfur fuel availability. Thus an end-of-2012 phase-in completion date would result in phase-ins as short as one year, thus degrading the industry's opportunity to distribute the redesign workload and departing from the pattern set by the highway program. Both of these are critical factors in our assessment that the proposed engine standards are feasible, and so a change to shorter phase-ins would jeopardize achievement of our environmental objectives for nonroad diesels. Therefore we are not adopting the suggested earlier completion of the phase-in.

As proposed, we are phasing in the Tier 4 NMHC standard for 75–750 hp engines with the NO_X standard, as is being done in the highway program. Engines certified to the new NO_X requirement would be expected to certify to the NMHC standard as well. The "phase-out" engines (those not certified to the new Tier 4 NO_X and NMHC standards) would continue to be certified to the applicable Tier 3 NMHC+NO_X standard. As discussed in section II.B, we believe that the NMHC standard is readily achievable through the application of PM traps to meet the PM standard, which does not involve such a phase-in. However, in the highway program we chose to phase in the NMHC standard with the NO_X standard to simplify the phase-in under the percent-of-production approach taken there, thus avoiding subjecting the "phase-out" engines to separate standards for NMHC and NMHC+NO_X (which could lead to increased administrative costs with essentially no different environmental result). The same reasoning applies here because, as in the highway program, the previous-tier standards are combined NMHC+NO_X standards. No commenters objected to this approach.

Because of the tremendous variety of engine sizes represented in the nonroad diesel sector, we are finalizing our proposed requirement that the phase-in requirement be met separately in both of the power categories with a phase-in (75–175 hp and 175–750 hp).[29] For example, a manufacturer that produces 1000 engines for the 2011 U.S. market in the 175 to 750 hp range would have to demonstrate compliance with the NO_X and NMHC standards on at least 500 of these engines, regardless of how many complying engines the manufacturer produces in the 75–175 hp category. (Note however that we are allowing averaging of emissions between these engine categories through the use of power-weighted ABT program credits.) We believe that this restriction reflects the availability of emissions control technology, and is needed to avoid erosion of environmental benefits that might occur if a manufacturer with a diverse product offering were to meet the phase-in with relatively low cost smaller engines, thereby delaying compliance on larger engines with much higher lifetime emissions potential. Even so, the horsepower ranges for these power categories are fairly broad, so this restriction allows ample freedom to manufacturers to structure compliance plans in the most cost-effective manner. There were no adverse comments on this approach.

[29] Note exceptions to the percent phase-in requirements during the phase-in model years discussed in sections III.L and III.M. These deal with differences between a manufacturer's actual and projected production levels, and with incentives for early or very low emission engine introductions.

b. Special Considerations for the 75–175 hp Category

As discussed in the proposal, the 75–175 hp category of engines and equipment may involve added workload challenges for the industry to develop and transfer technology. Though spanning only 100 hp, this category represents a great diversity of applications, and comprises a disproportionate number of the total nonroad engine and machine models. Some of these engines, though having characteristics comparable to many highway engines such as turbocharging and electronic fuel control, are not directly derived from highway engine platforms and so are likely to require more development work than larger engines to transfer emission control technology from the highway sector. Furthermore, the engine and equipment manufacturers have greatly varying market profiles in this category, from focused one- or two-product offerings to very diverse product lines with a great many models.

Therefore, in addition to the flexibility provided through the phase-in mechanism, we proposed two optional measures to provide added flexibility in implementing the Tier 4 NO_X standards, while keeping a priority on bringing PM emissions control into this diverse power category as quickly as possible. First, we proposed to allow manufacturers to use NMHC+NO_X credits generated by any Tier 2 engines over 50 hp (in addition to any other allowable credits) to demonstrate compliance with the Tier 4 requirement for 75–175 hp engines in 2012, 2013, and 2014 only. Second, we proposed allowing a manufacturer to instead demonstrate compliance with a reduced phase-in requirement of 25% for NO_X and NMHC in each of 2012, 2013, and the first 9 months of 2014. Full compliance (100% phase-in) with the Tier 4 standards would have needed to be demonstrated beginning October 1, 2014.

Engine manufacturers reinforced the points we made in the proposal regarding added workload challenges for this diverse category of engines and machines. However, they suggested that the first of the proposed options to address these challenges (allowing use of Tier 2 credits) is not likely to be used due to a lack of available Tier 2 credits, and therefore should be dropped, and that the second option (allowing a slower phase-in) provided too short a stability period, and should be modified to delay final compliance by an additional 3 months, to December 31, 2014 or January 1, 2015. In addition to describing the very large redesign workload, they pointed out that engines and machines in this category typically do not have a model year that differs from the calendar year, and so the substantial changes required for Tier 4 compliance in October 2014 could force the need to change the product for all of 2014, effectively shortening the phase-in to two years. One manufacturer argued that the compliance date for the 75–100 hp engines in this category should be delayed an additional year, to 2016, and that the start of the phase-in for these engines should be likewise delayed from 2012 to 2013.

We do not feel that the first option (allowing use of Tier 2 credits) should be dropped, as it provides an alternative flexibility mechanism for a power category in which flexibility is clearly important, and is environmentally helpful as it provides an option for manufacturers to achieve NO_X emission reductions earlier than under the second option. By providing an opportunity to use Tier 2 credits in the 75–175 hp category, it coordinates well with the Tier 2 credit use opportunity we are providing for the 50–75 hp engines meeting the 2008 PM standard (see section III.A), and allows for coordinated redesign and credit use planning by a manufacturer over this wide power range over many years. Nonetheless, recognizing that the second option may be more attractive to manufacturers, and considering the comments they provided on it, we have concluded that a three month phase-in extension until the end of 2014 is warranted to address the workload burden and to align product cycle dates. Thus we are adopting the December 31, 2014 implementation date suggested in comments for completion of the 75–175 hp engine phase-in.

We do not agree that an additional year of delay is appropriate for the 75–100 hp engines in this category. The comment expressing interest in our doing so did not provide any basis for it in technological feasibility or in workload burden, and we do not see any basis for it ourselves.

Therefore, we are adopting both of the proposed optional measures for the 75–175 hp engine phase-in, except that in the second option, full compliance (100% phase-in) with the Tier 4 standards will need to be demonstrated beginning December 31, 2014. As proposed, manufacturers using this reduced phase-in option will not be allowed to generate NO_X credits from engines in this power category in 2012, 2013, and 2014, except for use in averaging within the 75–175 hp category (that is, no banking or trading, or averaging with engines in other power categories). We believe that this restriction on credit use is appropriate, considering that larger engine categories will be required to demonstrate a substantially greater degree of compliance with the 0.30 g/bhp-hr NO_X standard several years earlier than engines built under this option. As the purpose of this option is to aid manufacturers in implementing Tier 4 NO_X standards for this challenging power category, we do not want any manufacturers who might be capable of building substantially greater numbers of cleaner engines to use this option as an easy and copious source of credits (owing to its slower phase-in of stringent standards) that in turn can be used to delay building clean engines in other categories or model years.

c. Alternative Phase-In Standards

To ensure that Tier 4 engine development is able to take maximum advantage of highway diesel technology advances, we proposed to adopt nonroad diesel provisions in the averaging, banking, and trading program that would parallel the heavy-duty highway engine program's "split family provisions" (see 68 FR 28470, May 23, 2003). In essence, these allow a manufacturer to declare an engine family during the phase-in years that is certified at NO_X levels roughly midway between the phase-out standard and phase-in standard, without the complication of tracking credit generation and use. Because they constitute a calculational simplification of the emissions averaging provisions, these split family provisions do not result in a loss in environmental benefits compared to what the phase-in can achieve.

The nonroad proposal also included specific emission levels for these split families, rather than just describing how they are calculated. Commenters suggested that we go one step further still and express these levels as alternative standards. They argued that this would facilitate attempts at harmonizing standards globally, especially for standards-setting bodies such as the European Commission that do not have emissions averaging programs. We are also aware that most manufacturers of highway diesel engines are now planning to comply with our 2007 standards using this emissions averaging approach, increasing the significance of comments on the topic from nonroad engine manufacturers, many of whom also make highway engines.[30]

After carefully considering the issues involved, we agree that the proposed approach lends itself to expression in terms outside of the averaging, banking, and trading program and that it makes sense to do so. We are creating such an alternative in the final regulations accordingly. These alternative standards do not substantively change our Tier 4 program from what we proposed, but rather respond to manufacturers' suggestions for administrative simplifications to what is essentially an averaging-based flexibility option in demonstrating compliance with the percent-of-production NO_X phase-in. The alternative NO_X phase-in standards are shown in table II.A–3. They apply only during the NO_X phase-in years. Manufacturers may use both approaches within a power category if desired, certifying some engines to the alternative standards, with the rest subject to the phase-in percentage requirement. Note that engines under 75 hp subject to Tier 4 NO_X standards do not have an alternative standard because they do not have a NO_X phase-in, and engines over 750 hp do not have an alternative standard because of the separate standards we are adopting for these engines (explained in section II.A.4).

TABLE II.A–3.—TIER 4 ALTERNATIVE NO_X PHASE-IN STANDARDS (G/BHP-HR)

Engine power	NO_X standard (g/bhp-hr)
75 ≤ hp < 175 (56 ≤ kW < 130)	[a] 1.7
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	1.5

Notes: [a] Under the option identified in footnote b of table II.A–2, by which manufacturers may meet an alternative phase-in requirement of 25/25/25% in 2012, 2013, and 2014 through December 30, the corresponding alternative NO_X standard is 2.5 g/bhp-hr.

The engines certified under these standards will of course also need to meet the Tier 4 PM and crankcase control requirements that take effect for all engines in the first phase-in year. They will also need to comply with all Tier 4 provisions that would apply to

[30] See the recently published "Highway Diesel Progress Review Report 2," EPA420–R–04–004, available at *http://www.epa.gov/otaq/diesel.htm#progreport2*.

phase-in engines, including the 0.14 g/bhp-hr NMHC standard and the NTE and transient test requirements for all pollutants. We recognize that this differs from what is required under the phase-in approach, in which these requirements would not apply to the 50% of engines categorized as "phase-out" engines. However, under the alternative standards approach, what would have been two different engine families (one meeting phase-in requirements and one meeting phase-out requirements, with NO_X and PM emissions averaging allowed between them under the ABT provisions) are replaced by a single engine family meeting the one set of alternative standards. Therefore all of the engines in this family must by default meet the phase-in requirements for provisions that lack any sort of averaging mechanism (NMHC standard, NTE, etc). As a result, any manufacturer choosing to design to the alternative standards rather than using the phase-in approach provides some additional environmental benefit as an indirect result of choosing this approach.

We also believe that this alternative standards provision makes appropriate a further adjustment to the NO_X phase-in scheme to better preserve both the advanced technology phase-in approach, for those manufacturers choosing that compliance path, and the alternative standards approach, for those choosing that path. Under the proposal, the provision for certifying a split engine family at a pre-designated NO_X level would not allow credit generation by or credit use on engines in the split family (other than for averaging within the family). This was consistent with our goal of providing a simple, single average NO_X standard level for the family, equivalent to arbitrarily designating a portion of the engines in the family as "phase-out" engines (credit generators) and the rest as "phase-in" engines (credit users) with a net credit balance of zero, while avoiding the burden of actually calculating and tracking credits. This was also consistent with our approach under the 2007 highway engine program from which this concept is derived.

However, because this split family provision has evolved into a set of alternative standards, there is no longer a need to prohibit the generation and use of ABT credits for these engines to preserve a de facto net zero credit balance, and so, considering that it is also not environmentally detrimental, we believe it is appropriate to allow credit use and generation for these engines as for other engines. A consequence of doing so, consistent with all of our ABT programs, is the adoption of NO_X FEL caps for these engines. To maintain the character of this compliance path as producing engines during the phase-in years that emit at NO_X levels which are roughly averaged between Tier 3 and final Tier 4 levels, we are setting NO_X FEL caps for these engines at levels reasonably close to the alternative standards. (See section III.A for details.) Because we are also maintaining the original phase-in/phase-out compliance path, a manufacturer wishing to build engines with NO_X levels higher than these FEL caps, at or approaching the Tier 3 levels, could still do so; in fact these would in actuality fit the description of a phase-out engine. This manufacturer would also, of course, have to produce a corresponding number of phase-in engines meeting the aftertreatment-based Tier 4 NO_X standards.

We also observe that the creation of alternative standards provides the opportunity to adjust the phase-in/phase-out provisions so as to reinforce their focus on introducing high-efficiency NO_X aftertreatment technology during the phase-in years, which is, of course, their aim. We are doing this by setting NO_X family emission limit (FEL) caps for phase-in engines at the same low levels as for Tier 4 engines produced in the post-phase-in years. (Again, see section III.A for details.) Although the engine manufacturers indicated in their comments that they did not believe it likely that anyone would choose this phase-in/phase-out compliance path, we believe that preserving it and focusing it on encouraging very low-NO_X engines as early as possible provides a potentially useful and environmentally desirable alternative path. Thus these two concepts have been developed to provide complementary compliance paths obtaining equivalent overall NO_X reductions, one focused on phasing in high-efficiency NO_X aftertreatment and the other on achieving NO_X control for all subject engines during the phase-in years at an average level between the Tier 3 and final Tier 4 standards levels.

3. Standards for Smaller Engines

a. Engines Under 25 hp

We are finalizing the Tier 4 program we proposed for engines under 25 hp. In the proposal we presented our view that standards based on the use of PM filters should not be set at this time for the very small diesel engines below 25 hp. We also discussed our plan to reassess the appropriate long-term standards in a technology review. However, for the nearer-term, we concluded that other proven PM-reducing technologies such as diesel oxidation catalysts and engine optimization could be applied to engines under 25 hp. Accordingly, we proposed Tier 4 PM standards to take effect beginning in 2008 for these engines based on use of these technologies.

In contrast to our proposals for other engine categories, the proposed Tier 4 standards for this category elicited very little comment from the engine manufacturers other than an expression of support for deferring consideration of any more stringent standards pending results of a future technology review. The States and environmental organizations expressed disappointment that EPA had not proposed more stringent standards for these engines, given the very large number of these engines in the field and the significant risk they pose due to individuals' exposure to diesel PM and air toxics. They urged more stringent 2008 PM standards and the adoption of standards obtaining emission reductions of 90% or more by the end of 2012. Emissions control manufacturers argued that more stringent 2008 standards based on the use of more efficient oxidation catalysts are feasible.

As discussed in section II.B.4, we continue to believe that the standards we proposed for engines under 25 hp are feasible, and commenters in the nonroad diesel industry provided no comments to the contrary. Our reasons for not proposing more stringent Tier 4 standards for these engines based on the use of PM filters and NO_X aftertreatment were mainly focused on the cost of equipping these relatively low cost engines with such devices, especially considering the prerequisite need for electronic fuel control systems to facilitate regeneration. The comments supporting more stringent standards were not convincing, as they did not address these cost issues. However, we do agree that these small engines likely have a large impact on human health, and, as discussed in section VIII.A, we are reaffirming the plan we described in the proposal to reassess the appropriate long-term standards for these engines in a technology review to take place in 2007. We will set more stringent standards for these engines at that time, if appropriate.

We also disagree with comments supporting more stringent 2008 standards that would require the use of diesel oxidation catalysts on all small engines. Although we agree that these catalysts can be applied so as to achieve emission reductions on some small engines, the emissions performance data we have analyzed do not support our setting a more stringent standard. Section 4.1.5 of the RIA summarizes such data showing a very wide range of engine-out PM emissions in this power category. Applying oxidation catalyst technology to these engines, though capable of some PM reduction if properly designed and matched to the application, is limited by sulfur in the diesel fuel. Specifically, precious-metal oxidation catalysts (which have the greatest potential for reducing PM) can oxidize the sulfur in the fuel and form particulate sulfates. Even with the 500 ppm maximum sulfur fuel available after 2007, the sulfate production potential is large enough to limit what can be done to set more stringent 2008 PM standards through the use of these catalysts. The 15 ppm maximum sulfur fuel available after 2010 will greatly improve the potential for use of oxidation catalysts, but as we discussed above, we believe that the much larger potential reduction afforded by PM filter technology warrants our waiting until the technology review in 2007 to evaluate the appropriate long-term standards for these engines. See section II.B.5 and RIA section 4.1.5 for further discussion.

When implemented, the Tier 4 PM standard and related provisions we are adopting today for engines under 25 hp will yield an in-use PM reduction of over 50% for these engines, and large reductions in toxic hydrocarbons as well. Achieving these emission reductions is very important, considering the fact that many of these smaller engines operate in populated areas and in equipment without closed cabs—in mowers, portable electric power generators, small skid steer loaders, and the like.

We are also adopting the alternative compliance option that we proposed for air-cooled, direct injection engines under 11 hp that are startable by hand, such as with a crank or recoil starter. As we explained in the proposal, the alternative is justified due (among other things) to these engines' need for loose design fit tolerances, their small cylinder displacement and bore sizes, and the difficulty in obtaining components for them with tight enough tolerances (68 FR 28363, May 23, 2003). This alternative allows manufacturers of these engines to delay Tier 4 compliance until 2010, and in that year to certify them to a PM standard of 0.45 g/bhp-hr, rather than to the 0.30 g/bhp-hr PM standard applicable beginning in 2008 to the other engines in this power category. As proposed, engines certified under this alternative compliance requirement will not be allowed to generate credits as part of the ABT program, although credit use by these engines will still be allowed.

We received no adverse comments on this proposed alternative for qualifying engines under 11 hp. Euromot commented that there are hand-startable engines in the 11–25 hp range, and that we should extend the alternative compliance option to these engines as well. However, hand-startability is not the sole defining feature of engines for which we established this alternative. Rather, the alternative is for a class of engines typified by a combination of characteristics (very small, air-cooled, direct injection, hand-startable), which give rise to the potential technical difficulties noted above. To extend the alternative to other engines simply because they have a hand-start is not justified, because they do not share these technical difficulties (or do not share them to the same degree). Such an extension could also potentially encourage manufacturers of the many models of these larger engines to market a hand-start option simply to avoid more stringent standards.

b. Standards for 25–75 hp Engines

We proposed a 0.22 g/bhp-hr PM standard for 25–75 hp engines, to take effect in 2008. We also proposed a filter-based 0.02 g/bhp-hr PM standard for these engines, to take effect in 2013, the year in which filter-based technology for these engines is expected to be applicable on a widespread basis (see section II.A.1). Also in 2013, the 25–50 hp engines would be subject to the 3.5 g/bhp-hr NMHC+NO_X standard already adopted for 50–75 hp engines (taking effect in 2008 as part of Tier 3). We are adopting all of these proposed standards in this final rule.

The 2008 PM standard for these engines should maximize reduction of PM emissions using technology available in that year. We believe that the 2008 PM standard is feasible for these engines, based on the same engine or oxidation catalyst technologies feasible for engines under 25 hp in 2008, following the introduction of nonroad diesel fuel with sulfur levels reduced below 500 ppm. We expect in-use PM reductions for these engines of over 50% (and large reductions in toxic hydrocarbons as well) over the five model years this standard would be in effect (2008–2012). These engines will constitute a large portion of the in-use population of nonroad diesel engines for many years after 2008. Although we are finalizing the 2013 standards for 25–75 hp engines today, we are also reaffirming our commitment to conducting a technology review for these standards in 2007. This planned review is discussed in section VIII.A. Additional discussion of our feasibility assessment for the 2008 and 2013 standards can be found in section II.B.4 and RIA section 4.1.4.

In comments, emissions controls manufacturers argued that more stringent 2008 standards for PM and NMHC based on the use of more efficient oxidation catalysts are feasible and should be adopted. Environmental organizations argued that PM and NO_X standards for 2008 should be set at more stringent levels, based on the use of oxidation catalysts and improved engine optimization. The California Air Resources Board argued for more stringent 2008 standards for HC+NO_X, PM and toxics, based on the use of oxidation catalysts.

We disagree with the comments calling for more stringent 2008 standards than proposed for 25–75 hp engines, based on the use of diesel oxidation catalysts. The standards we proposed and are adopting for these engines pull ahead sizeable PM reductions starting three years ahead of the earliest PM filter-based standards for any engine size. The pull-ahead standard level balances early reductions with the need to ensure that the PM filter-based standards and Tier 3 NMHC+NO_X standards are not jeopardized by an overemphasis on early reductions. Although we agree that oxidation catalysts can be applied to these engines, the emissions performance data we have analyzed do not support our setting a more stringent standard, for the same reasons described above in section II.A.3.a for engines under 25 hp. Refer to section II.B.4 and to section 4.1.4 of the RIA for additional discussion. For a discussion of comments opposed to new standards in 2008, see sections II.A.1 and II.B of this preamble.

We also do not agree that more stringent NO_X requirements based on improved engine optimization are appropriate for these engines in 2008. In 2001 we reviewed and confirmed the previously set NMHC+NO_X emission standards that will be in effect for these engines during the time frame in question.[31] Because of the focus we are putting on achieving large PM reductions from these engines as early as possible, we felt that it was important to strike a balance between PM and NO_X control. As a result, we did not propose more stringent NO_X standards for 50–75 hp engines, and we proposed to apply

[31] "Nonroad Diesel Emissions Standards Staff Technical Paper," EPA420–R–01–052, October 2001.

the 3.5 g/bhp-hr NMHC+NO_X standard to 25–50 hp engines in 2013 because this is the year in which the PM filter-based standard is being implemented. Requiring new NO_X controls for these engines earlier than 2013 would add a third redesign step to those already called for in 2008 and 2013. This would add a potentially unacceptable amount of redesign workload, to a point that it could jeopardize our objective of bringing stringent PM control to these engines as early as possible.

Consistent with the proposal, we are not setting more stringent NO_X standards for engines below 75 hp at this time based on the use of NO_X aftertreatment. As discussed in section 4.1.2.3 of the RIA, a high degree of complexity and engine/aftertreatment integration will be involved in applying NO_X adsorber technology to nonroad diesel engines. The similarity of larger nonroad engines (above 75 hp) to highway diesel engines, which will provide the initial experience base for this integration process, is key to our assessment that NO_X adsorbers are feasible for these engines. On the other hand, although engines under 75 hp are gradually increasing in sophistication over time, the accumulation of experience with designing and operating these engines with more advanced technology clearly lags significantly behind the sizeable experience base already developed for larger engines. At this point, we are unable to forecast how quickly adequate experience may accrue. Because this experience is crucial to ensuring the successful integration of the engines with NO_X adsorber technology, we are not adopting NO_X adsorber-based standards for engines under 75 hp in this final rule. Rather, as discussed in section VIII.A, we plan to undertake a technology assessment in the 2007 time frame which would evaluate the status of engine and emission control technologies, including NO_X controls, for engines less than 75 hp.

As described in section II.A.1.a, we are providing two PM standard compliance options to engine manufacturers for 50–75 hp engines. As part of this, we also proposed a measure to ensure that it would not be abused by equipment manufacturers who use engines that do not meet the PM pull-ahead standard in 2008–2011, but who then switch engine suppliers to avoid PM filter-equipped engines in 2012 as well (68 FR 28360, May 23, 2003). We proposed that an equipment manufacturer making a product with engines not meeting the pull-ahead standard in any of the years 2008–2011 must use engines in that product in 2012 meeting the 0.02 g/bhp-hr PM standard; that is, the equipment manufacturer would have to use an engine from the same engine manufacturer or from another engine manufacturer choosing the same compliance option. We also solicited comment on possible alternative solutions using a numerical basis, describing an example that would require the percentage of 50–75 hp machines equipped with PM filters in 2012 to be no less than the same percentage of 50–75 hp machines produced with non-pull-ahead engines in 2008–2011.

The Engine Manufacturers Association (EMA) and Deere commented on the unenforceability of the proposed "no switch" measure as part of a broader objection to our proposal for 50–75 hp engines. They pointed out that changing equipment model designations could easily allow an equipment manufacturer seeking to avoid PM filter-equipped engines in 2012 to declare a product in this model year a "new product," not the same as the 2008–2011 product. We have concluded that there is indeed potential for this abuse to occur and, although no one commented specifically on the alternative approach, we believe it clearly addresses this problem because it does not depend on product designations.

Therefore, we are adopting a provision to discourage engine switching based on this alternative approach. An equipment manufacturer who uses 50–75 hp engines will have three options:

(1) The manufacturer may exclusively use engines certified to the 0.22 g/bhp-hr PM standard (including through use of ABT credits) over the 2008–2011 period. This manufacturer is then free to use any number of 50–75 hp engines not certified to the 0.02 g/bhp-hr standards in 2012.

(2) The manufacturer may exclusively use engines not certified to the 0.22 g/bhp-hr PM standard over the 2008–2011 period. This manufacturer must then use only 50–75 hp engines that are certified to the 0.02 g/bhp-hr standards in 2012 (including through use of ABT credits).

(3) The manufacturer may use a mix of engines in 2008–2011. In this case, the manufacturer must calculate the percentage of 50–75 hp engines used (in U.S.-directed equipment) over the 2008–2010 period that are not certified to the 0.22 g/bhp-hr PM pull-ahead standard. Then the percentage of 50–75 hp engines this manufacturer uses in 2012 that are certified to the 0.02 g/bhp-hr PM standard must be no less than this 2008–2010 non-pull-ahead percentage figure minus a 5% margin.[32]

As an example of this third option, consider an equipment manufacturer who does not use the transition flexibility provisions (described in section III.B), and over the 2008–2010 period makes 1000 50–75 hp machines for use in the U.S., 200 (20%) of which use engines not certified to the 0.22 g/bhp-hr standard. In 2012, that manufacturer must make at least 15% of his 50–75 hp machines for use in the U.S. using engines certified to the 0.02 g/bhp-hr standard. We feel that the 5% margin is needed to allow for some reasonable sales shifts within the manufacturer's product offering over time, but is small enough to ensure that any possible advantage gained from selling higher-emissions products remains minimal. Equipment manufacturers must keep production records sufficient to prove compliance. This restriction and the percentage calculation will not apply to any 2008–2012 engines at issue that are being produced under the equipment manufacturer transition flexibility provisions discussed in section III.B. For example, if in addition to the 200 engines in 2008–2010 not certified to the 0.22 g/bhp-hr standard in the above example, this manufacturer also used 500 previous-tier engines in 2008–2010 under the flexibility allowance program, his percentage target for PM filter-equipped engines in 2012 would be 35% of all the engines used in 2012 that are not previous-tier engines under the flexibility allowance program.[33]

4. Standards for Engines Above 750 hp

We are adopting different Tier 4 standards for over 750 hp engines from those we proposed, and we are also adopting different implementation dates for these engine standards, though both the proposed and final programs have as their primary focus the implementation of high-efficiency exhaust emission controls as quickly as possible. The approach being adopted reflects our careful review of the technical issues presented by these engines. For some of these engines, we are accelerating standards based on the use of aftertreatment controls. For others, we are deferring a decision on such aftertreatment-based standards. This approach represents a feasible and efficient approach to redesigning

[32] The 2011 production is not included in the percentage calculation to avoid the need for post-2011 confirmation of production volumes which, as it would occur in 2012, would be too late to easily re-focus 2012 production if the confirmed volumes differ from projections. It is not likely that manufacturers would abuse the program by switching engine suppliers for this one year of production.

[33] That is: [200/(1000–500)] = 40%; subtracting the 5% margin then yields 35%.

engines and installing aftertreatment in a coordinated, orderly manner over a decade or more, and will achieve major reductions in PM and NO_X from these large diesel engines.

Under the proposal, all engines above 750 hp were treated the same, with a phase-in of PM and NO_X aftertreatment technology that started in 2011 and finished in 2014. The final standards are based on our evaluation of the differing technical issues presented by the two primary kinds of equipment in this category, mobile power generation equipment (generator sets) and mobile machinery. For both generator sets and mobile machinery, PM aftertreatment-based standards will start in 2015, with no prior phase-in. EPA is replacing the proposed phase-in with a PM standard starting in 2011 that is comparable to the overall level of control that the proposed phase-in would achieve. Differences within these applications, however, call for different approaches to the implementation of NO_X aftertreatment technology. For generator sets above 1200 hp, an aftertreatment-based NO_X standard will start in 2011, three years earlier than the date we proposed for full implementation of such standards. For generator sets below 1200 hp, the same aftertreatment-based NO_X standard will start in 2015. As with the PM standard, there is no phase-in. For engines used in mobile machinery, which is assumed to include all equipment that is not a generator set, EPA is deferring a decision on setting aftertreatment-based NO_X standards to allow additional time to evaluate the technical issues involved in adapting NO_X adsorber technology to these applications and engines. However, EPA is adopting a NO_X standard for these engines starting in 2011 that will achieve large NO_X reductions by relying on engine-based emissions control technology. Consistent with the different approaches we are taking to setting standards for engines above and below 750 hp, we are also adopting restrictions on ABT credit use between these power categories, as described in section III.A.

Consistent with the approach we took in previous standard-setting for these engines, we proposed that nonroad diesels above 750 hp be given more lead time than engines in other power categories to fully implement Tier 4 standards, due primarily to the relatively long product design cycles typical of these high-cost, low-sales volume engines and machines. Specifically, we proposed that this category of engines move directly from Tier 2 to Tier 4, and that the Tier 4 PM standard be phased in for these engines on the same 50–50–50–100% schedule as the NO_X and NMHC phase-in schedule, over the 2011–2014 model years. This would provide engine manufacturers with up to 8 years of design stability to address concerns specific to this category. Although we expressed our belief that these proposed provisions would enable the manufacturers to meet proposed Tier 4 engine standards, we also acknowledged concerns the manufacturers had expressed to us, and asked for comment on whether this category, or some subset of it defined by hp or application, should have a later phase-in start date, a later phase-in end date, adjusted standards, additional equipment manufacturer transition flexibility provisions, or some combination of these (68 FR 28364, May 23, 2003).

Comments from manufacturers of engines and equipment in this power category expressed their widespread view that the proposed standards were inappropriate in critical respects. In addition to reiterating the need for extra lead time due to long product design cycles, they pointed to difficulties with aftertreatment placement, with fabrication of the large filters that would be needed for these engines, with potential failures caused by uneven soot loading and regeneration in large filters, with stresses due to thermal gradients across large filters, and with mechanical stresses in mining applications with high shock loads. The manufacturers noted that aftertreatment-based standards for NO_X and PM were feasible for engines used in large mobile power generators. However, manufacturers did not believe aftertreatment-based NO_X standards could be implemented in the time frame proposed for engines used in large mobile machinery such as bulldozers and mine haul trucks. States, environmental organizations, and manufacturers of emissions controls, on the other hand, expressed support for the standards we proposed for these engines.

After evaluating these issues, EPA is adopting an approach that tailors the standards to the circumstances presented by the different kinds of engines in this power category. The NO_X standards we are adopting will achieve effective NO_X control by accelerating the proposed schedule for final NO_X standards based on high-efficiency NO_X aftertreatment for the largest generator sets, and by requiring engines in other generator sets to also meet aftertreatment-based NO_X standards, although we are delaying the implementation date for these standards compared to the implementation schedule we proposed. We believe that NO_X adsorber technology will be feasible for these generator set engines. We also believe that they may be an especially attractive application for Selective Catalytic Reduction (SCR) technology, which relies on the injection of urea into the exhaust stream. There are many stationary diesel generator sets using SCR today. Large mobile generator sets, though moved from location to location, operate much like stationary units once in place, with fuel (and potentially urea) delivered and replenished periodically. See section II.B.3 for further discussion.

For equipment other than generator sets, we are deferring a decision on setting aftertreatment-based NO_X standards to allow additional time to evaluate the technical issues involved in adapting NO_X control technology to these applications and engines. We are still evaluating the issues involved for these engines to achieve a more stringent NO_X standard, and believe that these issues are resolvable. We intend to continue evaluating the appropriate long-term NO_X standard for mobile machinery over 750 hp and expect to announce further plans regarding these issues (we are currently considering such an action in the 2007 time frame). The basis for the 0.50 g/bhp-hr NO_X standard we are adopting for generator sets over 750 hp is discussed in section II.B.3. We are also modifying the PM and NMHC standards we proposed (as well as certain implementation dates for these provisions), and modifying our proposed approach to ensuring transient emissions control for these engines (discussed in section III.F). The Tier 4 standards for engines over 750 hp are shown in table II.A–4.

TABLE II.A–4.—TIER 4 STANDARDS FOR ENGINES OVER 750 HP (G/BHP-HR)

	2011			2015		
	PM	NO_X	NMHC	PM	NO_X	NMHC
Engines used in:						
generator sets ≤1200 hp	0.075	2.6	0.30	0.02	0.50	0.14
generator sets >1200 hp	0.075	0.50	0.30	0.02	No new standard	0.14
all other equipment	0.075	2.6	0.30	0.03	No new standard	0.14

Unlike NO_X control technology, we believe that the more advanced state of PM filter technology development today makes their availability for these engines by 2015, with over ten years of development lead time, more certain, and so we are setting PM standards for both mobile machinery and generator sets based on use of this technology. We note in section II.B.3 that achieving durable PM filter designs for these large applications will likely require the use of wire mesh filter technology rather than the somewhat more efficient wall flow ceramic-based technology applicable to smaller engines, justifying the somewhat higher level for the 2015 PM standards shown in table II.A–4 (0.03 or 0.02 g/bhp-hr compared to 0.01 g/bhp-hr). Section II.B.3 also contains discussion of our bases for the other Tier 4 standard levels in this category. We believe that the 2015 implementation year (versus the proposed 2014 date for the fully phased-in standard) is necessary to allow development of the requisite technologies for these large engines, and to deal with the redesign workload Tier 4 will create for the many engine and equipment models in this category which, as noted, typically have very low production volumes and long product cycles.

For the purpose of determining which nonroad engines are subject to the generator set standards, we are defining a generator set engine as: "An engine used primarily to operate an electrical generator or alternator to produce electric power for other applications." This definition makes it clear that generator set engines do not include engines used in machines such as mine trucks that do mechanical work but that employ engine-powered electric motors to propel the machine, but they do include engines in nonroad equipment for which the primary purpose is to generate electric power, even if the machine is also self-propelled.

Similar to other power categories, we proposed a 50% phase-in to the final Tier 4 PM, NO_X and NMHC standards, with opportunity to average PM and NO_X between phase-in and phase-out engines in the 2011–2013 phase-in years via the ABT program. Because in this rule we are no longer phasing in to a final NO_X standard for some engines over 750 hp, it no longer makes sense to express the 2011 standards for these engines in this manner. Instead we are setting brake-specific emission standards effective in 2011. Furthermore, to avoid further complicating an already complex standards structure, we are adopting this pattern for the entire category, even with engines such as those used in generator sets for which the standards could still be expressed as a percent phase-in to final standards. Except for the pull-ahead of the long-term NO_X standard for large generator sets (which will increase the environmental benefit compared to the proposal), these 2011 PM and NO_X standards essentially correspond to averaged standards under a 50% phase-in to aftertreatment-based standards, hence our conclusion that the Tier 4 program will provide a level of control in 2011 that is substantially equivalent to that of the proposal. In addition, PM and NO_X emissions averaging through the ABT program will allow a manufacturer to comply by phasing in aftertreatment technologies as in the proposed program, should they desire to do so. Although there is no such averaging program for NMHC, the 2011 NMHC standard can be achieved without the use of advanced aftertreatment (as explained in section II.B.3), thus helping to enable a manufacturer to pursue this compliance strategy if desired.

This approach involving separate 2011 and 2015 standards is comparable to the proposed percent phase-in approach with emissions averaging. We believe that it enables manufacturers to redesign engines and equipment in a coordinated, orderly manner over a decade or more, and effectively gives targeted additional flexibility to the industry. Given the continuing availability of emissions averaging, we do not view this change as the creation of an additional, separate tier of standards compared to the proposal's phase-in of the Tier 4 standards.

5. Establishment of New Power Categories

We are finalizing our proposal to regroup the nine power categories established for previous tiers into the five Tier 4 power categories shown in table II.A–1. As we explained in the proposal, this regrouping will more closely match the degree of challenge involved in transferring advanced emissions control technology from highway engines to nonroad engines. The proposed choice of 75 hp as the appropriate cutpoint for applying aftertreatment-based NO_X control drew particular attention. In the proposal, we recognized that there is not an abrupt power cutpoint above and below which the highway-derived nonroad engine families do and do not exist, but noted further that 75 hp is a more appropriate cutpoint to generally identify nonroad engines in Tier 4 that will most likely be using highway-like engine technology than either of the closest previously-adopted power category cutpoints of 50 or 100 hp. Nonroad diesels produced today with rated power above 75 hp (up to several hundred hp) are mostly variants of nonroad engine platforms with four or more cylinders and per-cylinder displacements of one liter or more. These in turn are largely derived from or are similar to heavy-duty highway engine platforms. Even where nonroad engine models above 75 hp are not so directly derived from highway models, they typically share many common characteristics such as displacements of one liter per cylinder or more, direct injection fueling, turbocharging, and, increasingly, electronic fuel injection. These common features provide key building blocks in transferring high-efficiency exhaust emission control technology from highway to similar nonroad diesel engines. We therefore proposed to regroup power ratings using the 75 hp cutpoint.

The Engine Manufacturers Association and Euromot, which together represent the companies that make all but a tiny fraction of nonroad diesel engines sold in the U.S., expressed their support for the 75 hp cutpoint, as did every individual engine manufacturer who commented on this subject. These companies generally endorsed EPA's reasoning that the 75 hp level is appropriate to "delineate those engines (and applications) for which the application of on-highway like NO_X aftertreatment technologies is not likely to be feasible or practical" (EMA Comments p.10).

However, the Association of Equipment Manufacturers (AEM) and the equipment manufacturer Ingersoll-Rand commented that 100 hp is the more appropriate cutpoint for application of advanced NO_X control technology. They based this view on their observations that 75–100 hp engines do not share many of the characteristics of highway diesels, thus making technology transfer from the highway sector very costly, and customers will be negatively affected due to the relatively large cost impacts of NO_X aftertreatment on these smaller engines. They also argued that the 75 hp cutpoint would create significant misalignment in the global marketplace because European regulations do not use this cutpoint.

We agree with the equipment manufacturers' observation that there are engines above 75 hp without turbocharging or electronic controls. However, EPA did not choose the 75 hp cutpoint with the expectation that all engines above it had the same technology characteristics. There is a continuum in the degree to which key technology characteristics exist on engines throughout the power spectrum, and the 75 hp cutpoint was based on information from the current fleet of engines and on manufacturers' and EPA's expectations for future design trends, showing there is a marked difference in the prevalence of these and other key engine design characteristics for engines above and below 75 hp, and that, over time, 75–100 hp engines increasingly share advanced technology characteristics common in larger engines. Clear evidence of this trend over recent model years is documented in the RIA, section 4.1.4. As discussed in section II.B.2, the kind of engine technology generally employed by engines in the 75–100 hp range, combined with the lead time and phase-in provided for the Tier 4 NO_X standards, leads us to conclude that highway-like NO_X aftertreatment can be transferred to these engines. In addition, since our proposal, the Council of the European Union (EU) has issued a revised final version of new nonroad diesel emission standards that essentially aligns their power cutpoints with our own, including adoption of the 75 hp cutpoint for advanced technology NO_X control. EPA does not believe that the costs of meeting the NO_X standard for engines in the 75–100 hp range are unreasonable, and we refer the reader to section VI for a detailed discussion of our cost analysis for engines and equipment meeting Tier 4 standards in this power range. Moreover, EPA firmly believes such standards are technologically feasible for 75–100 hp engines. (See section II.B.2.)

Ingersoll-Rand also expressed concern that the proposed consolidation of 3 previous power categories into a single 175–750 hp category creates significant hardship by requiring the introduction of aftertreatment technologies in a single year, contrasting this with the Tier 2 standards, which phased in over 2001–2003 for these engines. In response, we note that the Tier 3 standards, which were set in the same rule that established the Tier 2 standards, will be introduced in a single year for these engines (2006), and that the Tier 2 phase-in over 3 years was established in response to particular issues and opportunities that were identified, specific to that time frame (see 62 FR 50181, September 24, 1997). In addition to the gradual phase-in of Tier 4 standards over several years, we are adopting significant flexibility provisions specifically to provide adequate lead time for equipment manufacturers to make the transition to the new standards, including some provisions that provide additional flexibility from what we proposed, as explained in section III.B.

6. CO Standards

We proposed minor changes in CO standards for some engines solely for the purpose of helping to consolidate power categories. We stated in the proposal that we were not exercising our authority to revise the CO standard for the purpose of improving air quality, but rather for purposes of administrative efficiency. However, manufacturers objected to these proposed changes, citing technological feasibility concerns, and a lack of parity with highway diesel and nonroad spark-ignition engines, given that existing CO standards levels for nonroad engines are already five times lower than the standard level for highway engines.

Because we proposed the CO standard changes for the sake of simplifying and consolidating power categories and not because of any technical considerations relating to emission reductions, we do not believe it productive to take issue with the views expressed that these proposed changes raise serious feasibility concerns. We instead are withdrawing this aspect of the proposal, the result being that the existing CO standards remain in place. In doing so, we are not considering or reexamining (and at proposal did not consider or reexamine) the substantive basis for those standards. Having multiple CO standards within a power category will, at worst, create minor inconveniences in certification and compliance efforts. As a result, in the less than 25 hp category, Tier 4 engines below 11 hp will continue to be subject to a different CO standard than 11–25 hp engines, identical to Tier 2. Likewise, different CO standards will continue to apply in Tier 4 to engines above and below 50 hp in the 25–75 hp category.

We do note, however, that we are applying new certification tests to all pollutants covered by the rule, the result being that Tier 4 engines will have to certify to CO standards measured by the transient test (NRTC) (which includes a cold start test), and the NTE. Our intent in adopting these new certification requirements is not to alter the level of stringency of the standard but rather to ensure robust control of emissions to this standard in use. The CO standards remain readily achievable using these tests, and we anticipate that no additional engine adjustments are necessary for the standards to be achievable (so there are no significant associated costs). We also explain there that the CO standards can be achieved without jeopardizing the ability to achieve all of the other engine standards.

7. Crankcase Emissions Control

We currently require the control of crankcase emissions from naturally-aspiriated nonroad diesel engines. We proposed to extend this requirement to turbocharged nonroad diesel engines as well, starting in the same model year that Tier 4 exhaust emission standards first apply in each power category.

EMA opposed the proposed extension, reiterating concerns expressed in comments on a similar proposed provision in the 2007 heavy-duty highway rule, including concerns over the impact that recirculating crankcase emissions may have on the feasibility of engine standards over the full useful life. These concerns are addressed in the Summary and Analysis of Comments document for that rule, which is included in the docket for today's rule. Besides the feasibility issues raised by EMA for nonroad diesels that are addressed in the highway rule, two nonroad-specific issues were raised as well: (1) The need to design crankcase emission control systems that operate at the high angularity experienced by some nonroad machines on uneven ground, and (2) the concern that this requirement adds to the large number of "first time" requirements being adopted for Tier 4. We agree that high angularity operation may add new design considerations for these controls, but do not see how it would pose a serious barrier that could not be overcome in time. The grouping of new EPA requirements in a specific model year is an important objective of our program aimed at providing stability to the design process, a goal much supported by the engine manufacturers. We have accounted for this in assessing feasibility, costs, and flexibility needs for the program. One flexibility we are providing is the three-path opportunity to satisfy our crankcase control requirement, as described below. In fact, in its written comments EMA recommended that, if EPA were to proceed with crankcase emission control requirements for Tier 4, it adopt all three options for demonstrating compliance. This is indeed what we are doing.

Thus, as proposed, in addition to allowing for compliance through the routing of crankcase emissions to the engine air intake system, we are also allowing manufacturers to instead meet the requirement by routing the crankcase gases into the exhaust stream, provided they keep the combined total of the crankcase emissions and the exhaust emissions below the applicable exhaust emission standards. Also as proposed, we are allowing manufacturers to instead meet the requirement by measuring crankcase emissions instead of completely eliminating them, provided manufacturers add these measured emissions to exhaust emissions in assessing compliance with exhaust emissions standards. Manufacturers using this option must also modify their exhaust deterioration factors or develop separate deterioration factors to account for increases in crankcase emissions as the engine ages, and must ensure that crankcase emissions can be readily measured in use. We see no reason to treat naturally-aspirated engines differently than turbocharged engines, and so are allowing these options for all Tier 4 engines subject to the crankcase control requirement, both turbocharged and naturally-aspirated. The wording of the proposed regulations limiting the options to turbocharged engines was inadvertent.

8. Prospects for International Harmonization

We received numerous comments, especially from engine and equipment manufacturers, stressing the need for EPA to work with other governmental standards-setting bodies to harmonize standards. We recognize the importance of harmonization of international standards and have worked diligently with our colleagues in Europe and Japan to achieve that objective. Harmonization of these standards will allow manufacturers continued access to world markets and lower the required research and development and tooling costs needed to meet different standards. We will continue to work with standards-setting governmental entities and with foreign and domestic manufacturers.

In October 2003, the Council and Parliament of the European Union reached agreement on revisions to a proposal developed by the European Commission that would amend Directive 97/68/EC to include nonroad diesel emissions standards similar to those in our Tier 4 program, and, as in the U.S., coordinated with low sulfur diesel fuel requirements in Europe. This revised proposal has since been finalized.[34] This revised Directive aligns well with our program in the Tier 4 time frame, even more so than did the original Commission proposal. It also closely aligns with our Tier 3 standards in the Tier 3 time frame.

For engines of 50–750 hp, the Directive's standards are very closely aligned with our own Tier 4 standards, including emissions levels, implementation dates, the defined power categories, and the lower hp limit of NO_X control based on high-efficiency exhaust emission controls (75 hp). Exceptions are noted below:

- The 2008 PM standard level for 50–75 hp engines (the equivalent of 0.3 g/bhp-hr vs our 0.22 g/bhp-hr level). Note, however, that we do allow certification to the 0.3 g/bhp-hr level as an option, provided the manufacturer must then meet our 0.02 g/bhp-hr standard in 2012, one year earlier than otherwise.
- The 2013 PM standard level for 50–75 hp engines (the equivalent of 0.01 g/bhp-hr vs our 0.02 g/bhp-hr level).
- An October 1, 2014 start for the final 75–175 hp NO_X standard (the same as our proposed date), compared to the December 31, 2014 date we are adopting in this final rule.
- For constant speed engines: no Tier 4-equivalent standards. Also, the EU's Tier 3-equivalent standards are not implemented on these engines until 2011–2012.

[34] Council of the European Union, "Directive of the European Parliament and of the Council amending Directive 97/68/EC", March 15, 2004.

As the EU program does not provide for emissions averaging, the alternative NO_X standards we are setting for 75–750 hp engines are the NO_X levels at which the EU standards are generally aligned during our NO_X phase-in years. The EU Directive also includes transition flexibility provisions for equipment manufacturers similar to those in our program, discussed in section III.B.

The EU program for nonroad diesels has not adopted or proposed any current or future standards for engines above 750 hp or below 25 hp, and its revised Directive for 25–50 hp engines does not subject them to any future standards beyond those entering into force in 2007 (equivalent to 0.45 g/bhp-hr PM and 5.6 g/bhp-hr hydrocarbon+NO_X), in contrast to our 2013 standards based the use of PM filters and more advanced engine-based control technologies (0.02 g/bhp-hr PM and 3.5 g/bhp-hr NMHC+NO_X). However, as discussed further in section VIII.A, the EU Directive includes plans to conduct a future technology review of appropriate standards for engines below 50 hp and above 750 hp. The year that this is planned for is 2007, the same year in which we are planning a technology review for engines below 75 hp. Considering progress to date, and announced plans for reviews in 2007, we believe that prospects for harmonized standards are excellent.

9. Exclusion of Marine Engines

For reasons outlined in the proposal, we are not applying Tier 4 standards to the marine diesel engines under 50 hp that are covered under our Tier 1 and 2 standards. We believe it is more appropriate to consider more stringent standards for a range of marine diesel engines, including these, in a future action. It should be noted that the existing Tier 2 standards will continue to apply to marine diesel engines under 50 hp until that future action is completed. We did not receive any adverse comments on this proposed approach.

B. Are the New Standards Feasible?

Today we are finalizing a program of stringent new standards for a broad category of nonroad diesel engines coupled with a new nonroad diesel fuel standard that dramatically lowers the sulfur level in nonroad diesel fuel ultimately to 15 ppm. We believe these standards are technically feasible in the leadtime provided given the availability of 15 ppm sulfur fuel and the rapid progress to develop the needed emission control technologies. We acknowledge, as pointed out by a number of commenters, that these standards will be challenging for industry to meet, in part due to differences in operating conditions and duty cycles for nonroad equipment and the diesel engines used in that equipment. Also, we recognize that transferring and effectively applying these technologies, which have largely been developed for highway engines, will require additional time after the application of the technology to on-highway engines. Diesel engine industry commenters and environmental stakeholder commenters on our proposal consistently agreed with our position that for most engine horsepower categories the technologies to meet the standards exist and that the transfer of these technologies to nonroad is possible. The biggest difference of opinions in the range of comments received by the Agency concerns the timing of the emission standards and the flexibility provisions (*i.e.*, the leadtime necessary to transfer the technology). One of the most important tasks for a feasibility analysis is to determine the appropriate amount of development time needed to successfully bring new technologies to market. We have carefully weighed the desire to have clean engines sooner, with the challenges yet to be overcome in applying the technologies to nonroad engines and equipment, in determining the appropriate timing and emission levels for the standards finalized today.

The RIA associated with today's action contains a detailed description and analysis of diesel emission control technologies, issues specific to applying these technologies to nonroad engines, and why we believe the new emission standards are feasible. Additional in-depth discussion of these technologies can be found in the final RIA for the HD2007 emission standards, the final RIA for the HD2004 emission standards, the 2002 Highway Diesel Progress Review and the recently released Highway Diesel Progress Review Report 2.[35] [36] [37] [38] The following sections summarize the challenges to applying these technologies to nonroad engines and why we believe the emission standards finalized today are technically feasible in the leadtime provided.

1. Can Advanced Diesel Emission Control Technologies Be Applied to Nonroad Engines and Equipment?

The emission standards and the introduction dates for those standards, as described earlier in this section, are premised on the transfer of diesel engine technologies being or already developed to meet light-duty and heavy-duty vehicle standards that begin in 2007. The advanced technology standards that we are finalizing today for engines over 25 horsepower will begin to go into effect four years later. This time lag between equivalent highway and nonroad diesel engine standards is necessary in order to allow time for engine and equipment manufacturers to further develop these highway technologies for nonroad engines and to align this program with nonroad Tier 3 emission standards that begin to go into effect in 2006.

This section summarizes the engineering challenges to applying advanced emission control technologies to nonroad engines and equipment, and why we believe that technologies developed for highway diesel engines can be further refined to address these issues in a timely manner for nonroad engines consistent with the emission standards finalized today.

a. Nonroad Operating Conditions and Exhaust Temperatures

Nonroad equipment is highly diverse in design, application, and typical operating conditions. This variety of operating conditions affects emission control systems through the resulting variety in the torque and speed demands (*i.e.*, power demands). In our proposal, we highlighted the challenge for design and implementation of advanced emission control technologies posed by this wide range in what constitutes typical nonroad operation. Some commenters emphasized their concerns regarding this issue as well, and their belief that these issues make the application of the technology to nonroad infeasible. While we recognize and agree with the commenters regarding the nature of the challenges, we disagree with their conclusion regarding feasibility because, as described in the following section, we see a clear path to overcome the challenges.

The primary concern for catalyst-based emission control technologies is exhaust temperature. In general, exhaust temperature increases with engine power and can vary dramatically as engine power demands vary. For catalyzed diesel particulate filters (CDPFs), exhaust temperature determines the rate of filter regeneration, and if too low, causes a need for supplemental means to ensure proper filter regeneration. In the case of the CDPF, it is the aggregate soot regeneration rate that is important, not the regeneration rate at any particular moment in time. A CDPF controls PM emissions under all conditions and can function properly (*i.e.*, not plug) even when exhaust temperatures are low for an extended time and the regeneration rate is lower than the soot accumulation rate, provided that occasionally exhaust temperatures and thus the soot regeneration rate are increased enough to regenerate the CDPF. Similarly, there is a minimum temperature (*e.g.*, 200 °C) for NO_X adsorbers below which NO_X regeneration is not readily possible and a maximum temperature (*e.g.*, 500 °C) above which NO_X adsorbers are unable to effectively store NO_X. Therefore, there is a need to match diesel exhaust temperatures to conditions for effective catalyst operation under the various operating conditions of nonroad engines.

Although the range of products for highway vehicles is not as diverse as for nonroad equipment, the need to match exhaust temperatures to catalyst characteristics is still present. This is an important concern for highway engine manufacturers and has been a focus of our ongoing 2007 diesel engine progress review. There we have learned that substantial progress is being made to broaden the operating temperature window of catalyst technologies while at the same time to design engine systems to better control average exhaust temperatures (for ongoing catalyst performance) and to attain periodically higher temperatures (to control PM filter regeneration and NO_X adsorber desulfation). Highway diesel engine manufacturers are working to address this need through modifications to engine design, modifications to engine control strategies, and modifications to exhaust system designs. New engine control strategies designed to take advantage of engine and exhaust system modifications can be used to manage exhaust temperatures across a broad range of engine operation. The technology solutions being developed for highway engines to better manage exhaust temperature are built upon the same emission control technologies (*i.e.*, advanced air handling systems and electronic fuel injection systems) that we expect nonroad engine

[35] Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, United States Environmental Protection Agency, December 2000, EPA420–R–00–026. Copy Available in EPA Air Docket A–2001–28 Item II–A–01.

[36] Regulatory Impact Analysis: Control of Emissions of Air Pollution from Highway Heavy-Duty Engines, United States Environmental Protection Agency, June 2000, EPA420–R–00–010. Copy available in EPA Air Docket A–2001–28 Item II–A–02.

[37] Highway Diesel Progress Review, United States Environmental Protection Agency, June 2002, EPA 420–R–02–016. Copy available in EPA Air Docket A–2001–28 Item II–A–52.

[38] Highway Diesel Progress Review Report 2, United States Environmental Protection Agency, March 2004, EPA420–R–04–004. Copy available in Docket OAR–2003–0012–0918.

manufacturers to use in order to comply with the existing Tier 3 emission standards.

Matching the emission control technology and the operating temperature window of the broad range of nonroad equipment may be somewhat more challenging for nonroad engines than for many highway diesel engines simply because of the diversity in equipment design and equipment use. Nonetheless, the problem has been successfully solved in highway applications facing low exhaust temperature performance situations as difficult to address as any encountered by nonroad applications. The most challenging temperature regime for highway engines are encountered at very light-loads as typified by congested urban driving with periods of extended idle operation. Under congested urban driving conditions, exhaust temperatures may be too low for effective NO_X reduction with a NO_X adsorber catalyst. Similarly, exhaust temperatures may be too low to ensure passive CDPF regeneration. To address these concerns, light-duty diesel engine manufacturers have developed active temperature management strategies that provide effective emissions control even under these difficult light-load conditions. Toyota has shown with their prototype diesel particulate NO_X reduction (DPNR) vehicles that changes to EGR and fuel injection strategies can realize an increase in exhaust temperatures of more than 100 °F under even very light-load conditions allowing the NO_X adsorber catalyst to function under these normally cold exhaust conditions.[39] Similarly, PSA Peugeot Citroen (PSA) has demonstrated effective CDPF regeneration under demanding light-load taxi cab conditions with current production technologies.[40] Both of these are examples of technology paths available to nonroad engine manufacturers to increase temperatures under light-load conditions.

While a number of commenters expressed concerns about low temperature operation for nonroad equipment, no commenters provided data showing that nonroad equipment in-use operating cycles would be more demanding of low temperature performance than passenger car urban driving. Both the Toyota and PSA systems are designed to function even with extended idle operation as would be typified by a taxi waiting to pick up a fare.

It is our conclusion that by actively managing exhaust temperatures, for example through engine management to increase exhaust temperatures, engine manufacturers can ensure highly effective catalyst-based emission control performance (*i.e.*, compliance with the emission standards across the applicable tests) and reliable filter regeneration across a wide range of engine operation as would be typified by the broad range of in-use nonroad duty cycles. Active methods of regenerating PM filters have been shown to be reliable under all operating conditions and can be applied to nonroad diesel engines in the time frame required by these regulations. The additional cost for active regeneration, beyond the cost for the PM filter alone, has been accounted for in the cost analysis summarized in section VI of this preamble.

We have conducted an analysis of various nonroad equipment operating cycles and various nonroad engine power density levels to better understand the matching of nonroad engine exhaust temperatures, catalyst installation locations and catalyst technologies. This analysis, documented in the RIA, shows that for many engine power density levels and equipment operating cycles, exhaust temperatures are quite well matched to catalyst temperature window characteristics. In particular, the nonroad transient cycle (NRTC), the cycle we are finalizing to use for certification for most engines with rated power less than 750 hp, was shown to be well matched to the NO_X adsorber characteristics with estimated performance in excess of 90 percent for a turbocharged diesel engine tested under a range of power density levels. The analysis also indicated that the exhaust temperatures experienced over the NRTC are better matched to the NO_X adsorber catalyst temperature window than the temperatures that would be expected over the highway FTP test cycle. This suggests (when coupled with the fact that PM filters function with equal effectiveness at essentially all conditions) that compliance based on testing with the nonroad Tier 4 standards on the NRTC will be somewhat easier, using similar technology, than complying with the highway 2007 emission standards on the highway transient test cycle.

In sum, we believe based on our analysis of nonroad engines and equipment operating characteristics, that, in use, some nonroad engines will experience conditions that require the use of temperature management strategies (*e.g.*, active regeneration) in order to effectively use the NO_X adsorber and CDPF systems. We have assumed in our cost analysis that all nonroad engines complying with a PM standard of 0.03 g/bhp-hr or lower will have an active means to control temperature (*i.e.* we have costed a backup regeneration system, although some applications likely may not need one). We have made this assumption believing, as indicated by a number of commenters, that manufacturers will not be able to accurately predict in-use conditions for every piece of equipment and will thus choose to provide the technologies on a back-up basis. As explained earlier, the technologies necessary to accomplish this temperature management are enhancements of both the Tier 3 emission control technologies that will form the starting point for Tier 4 engines larger than 50 hp, and the control strategies being developed for highway diesel engines.[41] Based on our analyses, we believe that there are no nonroad engine applications above 25 horsepower for which these highway engine approaches for temperature management will not work. However, we agree with commenters that given the diversity in nonroad equipment design and application, additional time will be needed in order to match the engine performance characteristics to the full range of nonroad equipment.

We have concluded that, given the timing of the emissions standards finalized today, and the availability and continuing development of technologies to address temperature management for highway engines which technologies are transferrable to all nonroad engines with greater than 25 hp power rating, nonroad engines can be designed to meet the new standards in the lead time provided, and can be provided to equipment makers in a timely manner within that lead time.

b. Nonroad Operating Conditions and Durability

Nonroad equipment is designed to be used in a wide range of tasks, from mining equipment to crop cultivation and harvesting to excavation and

[39] Sasaki, S., Ito, T., and Iguchi, S., "Smoke-less Rich Combustion by Low Temperature Oxidation in Diesel Engines," 9th Aachener Kolloquim Fahrzeug—und Motorentechnik 2000. Copy available in EPA Air Docket A–2001–28 Item II–A–56.

[40] Jeuland, N., *et al.*, "Performances and Durability of DPF (Diesel Particulate Filter) Tested on a Fleet of Peugeot 607 Taxis First and Second Test Phases Results," October 2002, SAE 2002–01–2790.

[41] We do not have Tier 3 emission standards for engines in the horsepower category from 25–50 hp. However, we expect that similar Tier 3 emission control technologies will form part of the emission control technology package used for compliance with the Tier 4 standards for these engines in 2013. Our cost analysis reflects the additional cost to apply these technologies for NO_X and PM control.

loading, and operated in harsh environments. In the normal course of equipment operation the engine and its associated hardware will experience levels of vibration, impacts, and dust that may exceed conditions typical of highway diesel vehicles. For this reason, some commenters said that the PM filter technology was infeasible for nonroad equipment. We disagree with this assertion and continue to believe that PM filter technologies can be applied to a wide range of nonroad equipment.

Specific efforts to design for the nonroad operating conditions will be required in order to ensure that the benefits of these new emission control technologies are realized for the life of nonroad equipment. Much of the engineering knowledge and experience to address these issues already exists with the nonroad equipment manufacturers. Vibration and impact issues are fundamentally mechanical durability concerns (rather than issues of technical feasibility of achieving emissions reductions) for any component mounted on a piece of equipment (*e.g.*, an engine coolant overflow tank). Equipment manufacturers must design mounting hardware such as flanges, brackets, and bolts to support the new component without failure. Further, the catalyst substrate material itself must be able to withstand the conditions encountered on nonroad equipment without itself cracking or failing. There is a large body of real world testing with retrofit emission control technologies on engines up to 750 hp that demonstrate the durability of the catalyst components themselves even in the harshest of nonroad equipment applications. The evidence for even larger engines (*i.e.*, those above 750 hp) is less conclusive because of the limited number of applications.

Deutz, a nonroad engine manufacturer, sold approximately 2,000 diesel particulate filter systems for nonroad equipment in the period from 1994 through 2000. The very largest of these systems were limited to engine sizes below 850 hp. The majority of these systems were sold into significantly smaller applications. Many of these systems were sold for use in mining equipment. Mining equipment is exposed to extraordinarily high levels of vibration, experiences impacts with the mine walls and face, and encounters high levels of dust. Yet in meetings with the Agency, Deutz shared their experience that no system had failed due to mechanical failure of the catalyst or catalyst housing.[42] The Deutz system utilized a conventional cordierite PM filter substrate as is commonly used for heavy-duty highway truck CDPF systems. The canning and mounting of the system was a Deutz design. Deutz was able to design the catalyst housing and mounting in such a way as to protect the catalyst from the harsh environment as evidenced by its excellent record of reliable function.

A number of commenters asserted that it was not possible to apply conventional CDPF technologies (*i.e.*, ceramic wall-flow filter media) to the largest diesel engines with power ratings above 750 hp. In the draft RIA for the proposal, we described our expectation that these highway-based systems could be assembled into larger systems to work well for these largest diesel engines. While we continue to believe that it may be possible in the time frame of this rulemaking for these conventional CDPFs to be applied to engines with more than 750 hp, based on the evidence provided by the commenters, we now agree that too much uncertainty remains for us to reach that conclusion today. We cannot clearly today describe a method to monitor the soot loading of individual filter elements in a parallel system made up of a significant number of smaller components. This is because for parallel systems the pressure drop (the best current method to monitor filter condition) across all of the parallel components is exactly the same. If a single filter begins to plug and needs to be regenerated it may not be detected in such a system. Therefore, we believe that instead of a massively parallel filter system, an alternate PM filtering media may be more appropriate in order to address issues of scalability, durability and packaging for these largest engines. Fortunately, there are other filter media technologies (*e.g.*, wire or fiber mesh depth filters) that can be successfully scaled to any size and which we have confidence in projecting today will be a more appropriate solution for the bulk of the engines in this size category. Because these depth filtration technologies are not quite as efficient at filtering PM as the ceramic systems that are the dominant solution for the smaller highway diesel engines, we are finalizing a set of PM filter-based standards for engines greater than 750 hp which are slightly higher than the proposed PM standards for these engines. Those standards are discussed in sections II.A and II.B.3 below. Our cost estimates summarized in section VI for engines greater than 750 hp are consistent with the use of either silicon carbide or wire mesh PM filter technologies.

Certain nonroad applications, including some forms of harvesting equipment, consumer lawn and garden equipment, and mining equipment, may have specific limits on maximum surface temperature for equipment components in order to ensure that the components do not serve as ignition sources for flammable dust particles (*e.g.*, coal dust or fine crop/lawn dust). Some commenters have raised concerns that these design constraints might limit the equipment manufacturers ability to install advanced diesel catalyst technologies such as NO_X adsorbers and CDPFs. This concern seems to be largely based upon anecdotal experience with gasoline catalyst technologies where under certain circumstances catalyst temperatures can exceed 1,000 °C and without appropriate design considerations could conceivably serve as an ignition source. We do not believe that these concerns are justified in the case of either the NO_X adsorber catalyst or the CDPF technology. Catalyst temperatures for NO_X adsorbers and CDPFs should not exceed the maximum exhaust manifold temperatures already commonly experienced by diesel engines (*i.e.*, catalyst temperatures are expected to be below 800 °C).[43] CDPF temperatures are not expected to exceed approximately 700 °C in normal use and are expected to only reach the 650 °C temperature during periods of active regeneration. Similarly, NO_X adsorber catalyst temperatures are not expected to exceed 700 °C and again only during periods of active sulfur regeneration as described in section III.C below. Under conditions where diesel exhaust temperatures are naturally as high as 650 °C, no supplemental heat addition from the emission control system will be necessary for regeneration and therefore exhaust temperatures will not exceed their natural level. When natural exhaust temperatures are too low for effective emission system regeneration

[42] "Summary of Conference Call between U.S. EPA and Deutz Corporation on September 19, 2002 regarding Deutz Diesel Particulate Filter System", EPA Memorandum to Air Docket A–2001–28 Item II–B–31.

[43] The hottest surface on a diesel engine is typically the exhaust manifold which connects the engines exhaust ports to the inlet of the turbocharger. The hot exhaust gases leave the engine at a very high temperature (800 °C at high power conditions) and then pass through the turbocharger where the gases expand driving the turbocharger providing work. The process of extracting work from the hot gases cools the exhaust gases. The exhaust leaving the turbocharger and entering the catalyst and the remaining pieces of the exhaust system is cooler (as much as 200 °C at very high loads) than in the exhaust manifold.

then supplemental heating, as described earlier, may be necessary but would not be expected to produce temperatures higher than the maximum levels normally encountered in diesel exhaust. Furthermore, even if it were necessary to raise exhaust temperatures to a higher level in order to promote effective emission control, there are technologies available to isolate the higher exhaust temperatures from flammable materials such as dust. One approach would be the use of air-gapped exhaust systems (*i.e.*, an exhaust pipe inside another concentric exhaust pipe separated by an air-gap) that serve to insulate the inner high temperature surface from the outer surface which could come into contact with the dust. The use of such a system also may be desirable in order to maintain higher exhaust temperatures inside the catalyst in order to promote better catalyst function. Another technology to control surface temperature already used by some nonroad equipment manufacturers is water cooled exhaust systems.[44] This approach is similar to the air-gapped system but uses engine coolant water to actively cool the exhaust system.

We thus do not believe that flammable dust concerns will prevent the use of either a NO_X adsorber or a CDPF because catalyst temperatures are not expected to be unacceptably high and because remediation technologies exist to address these concerns. In fact, exhaust emission control technologies (*i.e.*, aftertreatment) have already been applied on both an original equipment manufacturer (OEM) basis and for retrofit to nonroad equipment for use in potentially explosive environments. Many of these applications must undergo Underwriters Laboratory (UL) approval before they can be used.[45] Therefore, while we appreciate the commenters' concerns regarding safety, we remain convinced that the application of these emission control technologies will not compromise (or decrease) equipment safety.

We agree that nonroad equipment must be designed to address safety and durable performance for a wide range of operating conditions and applications that would not commonly be experienced by highway vehicles. We believe further as demonstrated by retrofit experiences around the world that technical solutions exist which allow catalyst-based emission control technologies to be applied to nonroad equipment.

2. Are the Standards for Engines 75–750 hp Feasible?

There are three primary test provisions and associated standards in the Tier 4 program we are finalizing today. These are the Nonroad Transient Cycle (NRTC), the existing International Organization for Standardization (ISO) C1 steady-state cycle, and the highway-based Not-To-Exceed (NTE) provisions.[46] Under today's rules, most nonroad diesel engines must meet the new standards for each of these three test cycles (the exceptions are noted below). Compliance on the transient test cycle includes weighting the results from a cold start and hot start test with the cold start emissions weighted at 1/20 and hot start emissions weighted at 19/20. Additionally, we have alternative optional test cycles including the existing ISO–D2 steady-state cycle and the Transportation Refrigeration Unit (TRU) cycle which a manufacturer can choose to use for certification in lieu of the NRTC and the ISO–C1, provided that the manufacturer can demonstrate to the Agency that the engine will only be used in a limited range of nonroad equipment with known operating conditions. A complete discussion of these various test cycles can be found in chapter 4.2, 4.3, and 4.4 of the RIA.

The standards we are finalizing today for nonroad engines with rated power from 75 to 750 hp are based upon the performance of technologies and standards for highway diesel engines which go into effect in 2007. As explained above, we believe these technologies, namely NO_X adsorbers and catalyzed diesel particulate filters enabled by 15 ppm sulfur diesel fuel, can be applied to nonroad diesel engines in a similar manner as for highway diesel engines. The combustion process and the means to modify that process are fundamentally the same for highway and nonroad diesel engines regardless of engine size. The formation mechanism and quantity of pollutants formed in diesel engines are fundamental characteristics of engine design and are not inherently different for highway and nonroad engines regardless of engine size. The effectiveness of NO_X adsorbers to control NO_X emissions and CDPFs to control PM, NMHC, and CO emissions are determined by fundamental catalyst and filter characteristics. Therefore, we disagree with commenters who suggest that these highway technology based emission standards are infeasible for nonroad engines. We acknowledge the comments raised regarding the unique characteristics nonroad diesel engines which must be considered in setting these standards, and we have addressed those issues by allowing (where appropriate) for additional lead time or slightly less stringent standards for nonroad diesel engines in comparison to highway diesel engines (and likewise have made appropriate cost estimates to account for the technology and engineering needed to address these issues).

PM Standard. We are finalizing a PM standard for engines in this category of 0.01 g/bhp-hr based upon the emissions reductions possible through the application of a CDPF and 15 ppm sulfur diesel fuel. This is the same emissions level as for highway diesel engines in the heavy-duty 2007 (HD2007) program (66 FR 5001, January 18, 2001). While emission levels of engine-out soot (the solid carbon fraction of PM) may be somewhat higher for some nonroad engines when compared to highway engines, these emissions are virtually eliminated (reduced by 99 percent) by the CDPF technology. With application of the CDPF technology, the soluble organic fraction (SOF) portion of diesel PM is predicted to be all but eliminated. The primary emissions from a CDPF equipped engine are sulfate PM emissions formed from sulfur in diesel fuel. The emissions rate for sulfate PM is determined primarily by the sulfur level of the diesel fuel and the rate of fuel consumption. With the 15 ppm sulfur diesel fuel, the PM emissions level from a CDPF equipped nonroad diesel engine will be similar to the emissions rate of a comparable highway diesel engine. Therefore, the 0.01 g/bhp-hr emission level is feasible for nonroad engines tested on the NRTC cycle and on the steady-state cycles, ISO–C1 and ISO–D2. Put another way, control of PM using CDPF technology is essentially independent of duty cycle given active catalyst technology (for reliable regeneration and SOF oxidation), adequate control of temperature (for reliable regeneration) and low sulfur diesel fuel (for reliable regeneration and low PM emissions). While some commenters argued that PM filters will

[44] "Engine Technology and Application Aspects for Earthmoving Machines and Mobile Cranes," Dr. E. Brucker, Liebherr Machines Bulle, SA, AVL International Commercial Powertrain Conference, October 2001. Copy available in EPA Air Docket A–2001–28, Docket Item # II–A–12.

[45] Phone conversation between Byron Bunker, United States Environmental Protection Agency and Dale McKinnon, Manufacturers of Emission Control Association (MECA), 9 April, 2003 confirming the use of emission control technologies on nonroad equipment used in coal mines, refineries, and other locations where explosion proofing may be required.

[46] As an alternative to compliance with the ISO C1 test procedure, a manufacturer can show compliance with the standards by testing over the Ramped Modal Cycle (RMC) as described in section III.F.

not enable the 0.01 PM emission standard for nonroad engines, we remain convinced by the demonstration of 0.01 or lower PM emission levels from a number of diesel engines described in the RIA, that the standard is feasible given the leadtime provided and the availability of 15 ppm sulfur diesel fuel. Likewise, the NTE provisions for nonroad engines are the same as for on-highway engines meeting an equivalent PM control level. The maximum PM emission level from a CDPF equipped diesel engine is primarily determined by the maximum fuel sulfur conversion level experienced at the highest operating conditions. As documented in RIA chapter 4.1.1.3, testing of diesel engines at conditions representative of the highest sulfate PM formation rates shows PM levels below the level required by the NTE provisions when tested on less than 15 ppm sulfur diesel fuel.

NO_X Standard. We are finalizing a NO_X standard of 0.30 g/bhp-hr for engines in this category based upon the emission reductions possible from the application of NO_X adsorber catalysts and the expected emission levels for Tier 3 compliant engines which form the baseline technology for Tier 4 engines. The Tier 3 emission standards are a combined NMHC+NO_X standard of 3.0 g/bhp-hr for engines greater than 100 hp and less than 750 horsepower. For engines less than 100 hp but greater than 50 horsepower the Tier 3 NMHC+NO_X emission standard is 3.5 g/bhp-hr. We believe that in the time-frame of the Tier 4 emission standards, all engines from 75 to 750 hp can be developed to control NO_X emissions to engine-out levels of 3.0 g/bhp-hr or lower.[47] This means that all engines will need to apply Tier 3 emission control technologies (*i.e.*, turbochargers, charge-air-coolers, electronic fuel systems, and for some manufacturers EGR systems) to get to this baseline level. As discussed in more detail in the RIA, our analysis of the NRTC and the ISO–C1 cycles indicates that the NO_X adsorber catalyst can provide a 90 percent or greater NO_X reduction level on the cycles. The standard of 0.30 g/bhp-hr reflects a baseline emissions level of 3.0 g/bhp-hr and a greater than 90 percent reduction of NO_X emissions through the application of the NO_X adsorber catalyst. The additional lead time available to nonroad engine manufacturers and the substantial learning that will be realized from the introduction of these same technologies to highway diesel engines, plus the lack of any fundamental technical impediment, makes us confident that the new NO_X standards can be met.

Given the fundamental similarities between highway and nonroad diesel engines, we believe that the NO_X adsorber technology developed for highway engines can be applied with equal effectiveness to nonroad diesel engines with additional developments in engine thermal management (as discussed in section II.B.2 above) to address the more widely varied nonroad operating cycles. In fact, as discussed previously, the NO_X adsorber catalyst temperature window is particularly well matched to transient operating conditions as typified by the NRTC.

As pointed out by some commenters, compliance with the NTE provisions will be challenging for the nonroad engine industry due to the diversity of nonroad products and operating cycles. However, the technical challenge is reduced somewhat by the 1.5 multiplier used to calculate the NTE standard as discussed in section III.J. Controlling NO_X emissions under NTE conditions is fundamentally similar for both highway and nonroad engines. The range of control is the same and the amount of reduction required is also the same. We know of no technical impediment, nor were any raised by commenters, that would prevent achieving the NTE standard under the zone of operating conditions required by the NTE.

NMHC Standard. Meeting the NMHC standard under the lean operating conditions typical of the biggest portion of NO_X adsorber operation should not present any special challenges to nonroad diesel engine manufacturers. Since CDPFs and NO_X adsorbers contain platinum and other precious metals to oxidize NO to NO_2, they are also very efficient oxidizers of hydrocarbons. NMHC reductions of greater than 95 percent have been shown over transient and steady-state test procedures.[48] Given that typical engine-out NMHC is expected to be in the 0.40 g/bhp-hr range or lower for engines meeting the Tier 3 standards, this level of NMHC reduction will mean that under lean conditions emission levels will be well below the standard. For the same reasons, there is no obstacle which would prevent achieving the NTE standard.

Under the brief episodic periods of rich operation necessary to regenerate NO_X adsorber catalysts, it is possible to briefly experience higher levels of NMHC emissions. Absent a controlling standard, it is possible that these NMHC emissions could be high. There are two possible means to control the NMHC emissions during these periods in order to meet the NMHC standard finalized today. Manufacturers can design the regeneration system and the oxygen storage (oxidation function under rich conditions) of the NO_X adsorber catalyst such that the NMHC emissions are inherently controlled. This is similar to the control realized on today's three-way automotive catalysts which also experience operation that toggles between rich and lean conditions. Secondly, a downstream clean-up catalyst can be used to oxidize the excess NMHC emissions to a level below the standard. This approach has been used in the NO_X adsorber demonstration program at EPA described in the RIA. Our cost analysis for engines in the 75 to 750 hp category includes a cost for a clean-up catalyst to perform this function.

Cold Start. The standards include a cold start provision for the NRTC procedure. This means that the results of a cold start transient test will be weighted with the emissions of a hot start test in order to calculate the emissions for compliance against the standards. In a change from the proposed rule, the weightings are 1/20 cold start and 19/20 for the hot start (as opposed to the proposed weightings of 1/10 and 9/10, respectively) as described more fully in chapter 4.2 of the RIA and section III.F below. Because exhaust temperatures are so important to catalyst performance, a cold start provision is an important tool to ensure that the emissions realized in use are consistent with the expectations of this program. Achieving this standard represents an additional technical challenge for NO_X control and to a lesser extent CO and NMHC control (*i.e.*, control of gaseous pollutants). PM control with a CDPF is not expected to be significantly impacted by cold-start provisions due to the primary filter mechanism being largely unaffected by temperature.

With respect to achievability of the NO_X, CO and NMHC standards, during the initial start and warmup period for a diesel engine, the exhaust temperatures are typically below the light-off temperature of a catalyst. As a result, exhaust stack emissions may initially be higher during this period of

[47] For engines between 75 and 100 horsepower, this may require re-optimization of the engine to lower NO_X emissions if they are higher than 3.0, but we would not expect any new hardware beyond the Tier 3 hardware to be required in the Tier 4 timeframe to accomplish this reduction.

[48] "The Impact of Sulfur in Diesel Fuel on Catalyst Emission Control Technology," report by the Manufacturers of Emission Controls Association, March 15, 1999, pp. 9 & 11. Copy available in EPA Air Docket A–2001–28 Item II–A–67.

operation. The cold start test procedure is designed to quantify these emissions to ensure that emission control systems are designed appropriately to minimize the contribution of cold-start emissions. Cold-start emissions can be minimized by improving catalyst technology to allow for control at lower exhaust temperatures (*i.e.*, by lowering the catalyst light-off temperature) and by applying strategies to quickly raise the exhaust temperature to a level above the catalyst light-off temperature.

There are a number of technologies available to the engine manufacturer to promote rapid warmup of the exhaust and emission control system. These include retarding injection timing, increasing EGR, and potentially late cycle injection, all of which are technologies we expect manufacturers to apply as part of the normal operation of the NO_X adsorber catalyst system. These are the same technologies we expect highway engine manufacturers to use in order to comply with the highway cold start FTP provision which weights cold start emissions more heavily with a 1/7 weighting. As a result, we expect the transfer of highway technology to be well matched to accomplish this control need for nonroad engines as well. Using these technologies we expect nonroad engine manufacturers to be able to comply with the new Tier 4 NO_X, CO, and NMHC emission standards including the cold start provisions of the transient test procedure.

One commenter has raised the concern that if diesel engines are no cleaner than 3 g/bhp-hr NO_X and if NO_X adsorbers can be no more efficient than 90 percent, then any increase in NO_X emissions above the 0.30 g/bhp-hr level on a cold-start test will make the emission standards infeasible. We should clarify, when discussing the emission reduction potential of the NO_X adsorber catalyst generically in the NPRM, we have sometimes simply stated that it is 90 percent or more effective without plainly saying that this refers to our expectation for average performance considering both cold and hot start emissions. More precisely then, we would expect lower effectiveness over the cold-start test procedure with somewhat higher effectiveness realized over the hot-start test procedure. Because of the relative weightings of the two test cycles (*i.e.*, 1/20 for the cold-start and 19/20 for the hot-start), although the degradation of performance below 90 percent over the cold-start cycle can be substantially greater than the performance above 90 percent realized over the hot-start cycle, the standards remain feasible. For example, even if the average NO_X adsorber performance over the cold-start test cycle was only 70 percent, the average NO_X adsorber performance over the hot-start portion of the test cycle would only need to be 91 percent in order to realize a weighted average performance of 90 percent. Similarly, were the cold-start test cycle performance only 50 percent, the hot-start performance would only need to be 92 percent in order to realize a weighted average performance of 90 percent.[49] We are confident, based on our estimates of NO_X adsorber performance over the nonroad test cycle summarized in the RIA, that NO_X adsorber performance in excess of 92 percent can be expected in the time frame of the requirements finalized today.

Complying with the PM standard given consideration of the cold start test procedure is not expected to be as challenging as compliance with the NO_X standard. The effectiveness for PM filtration is not significantly effected by exhaust temperatures, as noted earlier. Thus, PM emission levels are similar over the cold and hot start tests.

The standards that we are finalizing today for nonroad engines with rated horsepower levels from 75 to 750 hp are based upon the same emission control technologies, clean 15 ppm or lower sulfur diesel fuel, and relative levels of emission control effectiveness as the HD 2007 emission standards. We have given consideration to the diversity of nonroad equipment for which these technologies must be developed and the timing of the Tier 3 emissions standards in determining the appropriate timing for the Tier 4 standards. Based upon the availability of the emission control technologies, the proven effectiveness of the technologies to control diesel emissions to these levels, the technology paths identified here to address constraints specific to nonroad equipment, and the additional lead time afforded by the timing of the standards, we have concluded that the standards are technically feasible in the leadtime provided.

3. Are the Standards for Engines Above 750 hp Feasible?

The preceding discussion of the standards for engines of 75 to 750 hp highlights the main thrust of our new Tier 4 program, a focus on realizing very low on-highway like emission levels for the vast majority of nonroad diesel engines. The emission standards and the combination of technologies that we expect will be used to meet those standards are virtually identical to the HD2007 program for on-highway engines. The following three sections (II.B.3, II.B.4, and II.B.5) describing the feasibility of the standards for engines above 750 hp, from 25 to 75 hp, and below 25 hp, while following the same pattern and objective, take additional consideration of the fact that engines and equipment in these size categories have no direct on-highway equivalent and differ from highway engines in substantial ways that cause us to reach differing conclusions regarding the appropriate standards and timing for those standards. Whether in scale, or use, or operating conditions, the characteristics of these engines and equipment are such that we have taken particular consideration of them in setting the timing and level of the standards. The remainder of this section (II.B.3) discusses what makes the above 750 hp category unique and why the standards which we are adopting are technologically feasible.

a. What Makes the Over 750 hp Category Different?

The first and most obvious difference for engines in this horsepower category is scale. No on-highway engines come close to the size of the largest engines in this category which can produce in excess of 3,000 horsepower, consist of 16 or more cylinders and have 12 or more turbochargers. The engines, and the equipment that they power, are quite simply significantly larger than any on-highway diesel engine. Many commenters argued that emission technologies from on-highway vehicles could not be simply scaled up for these larger engines and that if they were, the consequences of this resizing would include structural weakness and reduced system robustness. As discussed below, our review of the information provided with these comments and our subsequent analysis of the technical characteristics of some emission control components has led us to conclude that revised emission standards (based on performance of different technologies that those whose performance formed the basis for the proposed rule) from those we proposed for this horsepower category are appropriate and available.

We have concluded that it is appropriate to distinguish between two broad categories of engines over 750 hp grouped by application: Mobile machines and generator sets. Mobile machines include the very largest nonroad equipment used in mining trucks and large excavation equipment.

[49] The combined weighted average performance is calculated as 1/20 (cold-start) + 19/20 (hot-start). Hence it can be seen that 1/20 (70%) + 19/20 (91%) = 90% and likewise that 1/20 (50%) + 19/20 (92%) = 90%.

The environment and operating conditions (especially for vibration) represent the harshest application into which nonroad engines are applied. Design considerations for technologies used to control emissions from engines in these applications must first consider robustness to the harsh environments that will be experienced in use. In contrast, mobile nonroad generator sets operate in relatively good operating environments. In addition, while mobile nonroad generator sets can, and are moved between operating locations, they are always stationary during actual operation. Thus the levels of vibration and the general environment for engine operation are significantly less demanding for generator sets than for mobile machines. Also the dynamic range of operation is significantly narrower and less demanding for generator sets. Designed to operate at a set engine speed, synchronous to the frequency cycle desired for electric generation (*i.e.*, 1200 or 1800 RPM for 60 hz), diesel engines designed for generator set applications can be optimized for operation in this narrow range.

We have given specific consideration to the unique engineering challenges for engines in this horsepower category in determining the appropriate emission standards set in today's action. We have also taken into account the important differences between generator set applications and other mobile applications in developing standards for this horsepower category.

b. Are the New Tier 4 Standards for Over 750 hp Engines Technologically Feasible?

The emission standards described in section II.A above describe a comprehensive program for engines over 750 hp that give consideration to both the physical size of these engines and the applications into which these engines are applied. Engines in this power category must show compliance with the C1 or D2 steady-state test cycles as appropriate as well as with the NTE provisions finalized today. As described in sections III.F and III.G, these engines will not be tested over the NRTC nor will they be subject to a cold-start test procedure. The feasibility discussion in this section describes expected performance of the engines over the required test cycles and the NTE. This section will briefly summarize the feasibility analysis contained in the RIA for these engines.

PM Standards. Beginning in 2011 all nonroad diesel engines above 750 hp must meet a PM standard of 0.075 g/bhp-hr. We believe that this PM standard is feasible based on the substantial reductions in sulfate PM due to the use of 15 ppm sulfur diesel fuel and the potential to improve the combustion process to reduce PM emissions formed in the engine. Specifically, we believe based on the evidence in the RIA that increasing fuel injection pressure, improving electronic controls and optimizing the combustion system geometry will allow engine manufacturers to meet this level of PM control in 2011. Some engine manufacturers have in fact indicated to the Agency that this level of control represents an achievable goal by 2011. One commenter argued however, that a more relaxed standard of 0.1 g/bhp-hr based on today's on-highway diesel engine performance would be appropriate. We disagree with this comment, believing that given the substantial leadtime available and the potential for further improvements in combustion systems, that it is appropriate to set a forward looking PM standard of 0.075 g/bhp-hr. Conversely, other commenters argued that future on-highway PM filter technology should be applied to this class of engines as early as 2011 (*i.e.*, that a standard of 0.01 g/bhp-hr PM is appropriate). While we agree with the commenters that in the long-term it will be appropriate to apply filter-based emission control technologies to these engines, we do not agree that such control is appropriate as early as 2011. As the following section explains, we believe that there are remaining technical challenges to be addressed prior to the application of PM filters to these engines and that it is necessary to allow additional leadtime for those challenges to be addressed.

Beginning in 2015 all nonroad engines over 750 hp must meet stringent PM filter technology-based emission standards of 0.02 g/bhp-hr for engines used in generator set applications and 0.03 g/bhp-hr for engines used in mobile machine applications. We are predicating these emission standards based on the application of a different form of diesel particulate filter technology, a wire or fiber mesh depth filter rather than a ceramic wall flow filter. Wire mesh filters are capable of reducing PM by 70 percent or more. We have not based these standards upon the more efficient (>90 percent) control possible from ceramic wall flow style PM filters, because we believe that the application of the wall flow filter technology on engines of this size has not been adequately demonstrated at this time. While it would certainly be possible to apply the ceramic-based technology to these larger engines, we cannot today conclude with certainty that such systems would be as robust in-use as needed (see earlier discussion in section II.B.1.b). Considering the information available to the Agency today, we believe it appropriate to set the long term PM standard for these very large engines based on technologies which we can project with confidence will give high levels of emission reduction, durability, and robustness when scaled to these very large engine sizes.

The 0.01 g/bhp-hr difference in the PM emission standards between the standard for generator sets and for other mobile applications in this category (0.01 g/bhp-hr lower for generator sets) reflects our expectation that engine-out emissions from generator sets can be reduced below the level for mobile machines due to generator set operation at a single engine speed. Without the need to provide full power and control over the wider range of possible operating conditions that mobile machines must deliver, we believe that the air handling systems (especially the turbocharger match to the engine) can be improved to provide a moderate reduction in engine-out emissions. This, coupled with the reduction afforded by the PM filter technology, would allow generator sets to meet a more stringent 0.02 g/bhp-hr standard. Diesel engines designed for use in generator sets meeting this standard will need to demonstrate compliance over the appropriate test cycles, either the ISO C1 or D2 tests. As discussed in RIA chapter 4.3.6.2, PM emission rates are nearly the same for steady-state testing or for alternative ramped modal cycle (RMC) testing. These test cycles, like the engines, are designed to be representative of the range of operation expected from a generator set.

As discussed previously, PM emission control over the NTE region for PM filter equipped diesel engines is predominantly a function of sulfate formation at high exhaust temperatures. Given that fuel consumption (and thus sulfur) consumption rates on a brake specific basis tend to be lower for engines above 750 hp, we can conclude that the increase in PM emissions over the NTE region will likely be lower for these engines than for engines meeting the 0.01 g/bhp-hr standard. Thus, we can conclude based on the evidence in the RIA that compliance with the NTE provisions for PM is feasible for engines over 750 hp.

Although we are projecting that manufacturers will comply with this standard using a slightly less efficient PM filter technology, we remain convinced that 15 ppm sulfur diesel fuel will still be a necessity for this technology to be applied. Regardless of the filter media chosen for the PM filter, the filter will still require catalyst-based systems to ensure robust regeneration and adequate control of the SOF portion of PM. As these catalyst-based technologies are adversely impacted by sulfur in diesel fuel as described in II.C below, 15 ppm sulfur diesel fuel will be required in order to ensure compliance with the PM standards finalized here for engines over 750 hp.

NO_X Standards. As with the PM standards, we are setting distinct NO_X standards for this category of engines reflecting particular concerns with the application of technologies to engines of this size and our desire to realize significant NO_X reductions as soon as possible. There are two sets of NO_X standards that we are finalizing today, a 0.50 g/bhp-hr NO_X standard for engines used in generator set applications and a 2.6 g/bhp-hr NO_X standard for mobile machines.

For engines used in generator set applications we are finalizing a 0.50 g/bhp-hr standard that goes into effect for engines above 1,200 hp in 2011 and in 2015 for engines above 750 hp. We see two possible technology options for manufacturers to meet these standards. First, compliance with this NO_X standard will be possible through the application of a dual bed NO_X adsorber system (*i.e.*, a system that allows regeneration to be controlled external to the engine). This approach can work well for generator set applications where packaging constraints and vibration issues are greatly reduced. Since this approach requires limited engine redesign, it would be an appealing approach for these large engines sold in very low volumes. NO_X adsorber systems for stationary power generation (systems that never move) are available today on a retrofit basis, and we believe with further development to address packaging and durability concerns that similar systems can be applied to mobile generator sets.[50]

A second possible technology option for engines in this category is urea SCR. The challenges for urea SCR in mobile applications are well known, specifically a lack of urea infrastructure to provide urea refill at diesel fueling locations and a need to ensure that urea is added as necessary in use.[51] These hurdles can be addressed more easily for generator sets than for virtually any other mobile source emission category. Although nonroad generator sets are mobile, in operation they remain at a fixed location where fuel is delivered to them periodically (*i.e.*, a 1,200 hp generator set does not and cannot pull into the local truck stop for a fuel fill). Therefore, the same infrastructure that currently provides urea delivery for stationary power generation can also be utilized for nonroad generator set applications.[52] It would still remain for the manufacturer to develop a mechanism to ensure urea refill, but we believe it is likely that solutions to this problem can be addressed through monitoring as for stationary source emissions or other technology options (*e.g.*, a urea interlock that precludes engine operation without the presence of urea).

Either of these technology approaches could be applied to realize an approximately 90 percent reduction from the current Tier 2 emission levels for these engines in order to comply with an emission standard of 0.50 g/bhp-hr. The 0.50 g/bhp-hr standard is different from our proposed level of 0.30 g/bhp-hr reflecting the changes we have made in this final action to the implementation schedule for this class of engines and therefore our projections for a technology path. At the time of the proposal, we projected that this class of engine would follow an integrated two-step technology path. We are now finalizing a program that anticipates the application of 90 percent effective NO_X control to diesel engines for use in generator sets without a reduction in engine-out NO_X levels beyond Tier 2. This reflects our desire to focus on getting the largest emission reduction possible in the near term (beginning in 2011) from these engines. Where we believe additional technology development is needed, as is the case for mobile machines over 750 hp, we are finalizing a more gradual emission reduction technology pathway anticipating further reductions in engine-out NO_X emissions followed by a possible future action to reduce emissions further as described in section II.A. RIA chapter 4.1.2.3.3 describes NO_X adsorber effectiveness to control NO_X emissions including effectiveness over the NTE region. The discussion there is equally applicable to engines above and below 750 hp regarding NTE performance because the key attribute of NTE performance (exhaust temperature) is similar for engines across the horsepower range.

For engines over 750 hp used in mobile machines (and for 750–1200 hp generator sets from 2011 until 2015) we are setting a new NO_X standard of 2.6 g/bhp-hr beginning in 2011. We are predicating this level of emission control (an approximate 50 percent reduction from Tier 2) on an improved combustion system and proven engine-based NO_X control technologies. Specifically, we believe manufacturers can apply either proven cooled EGR technology, or apply additional levels of engine boost, a limited form of Miller Cycle operation, and increased intercooling capacity for the two-stage turbocharging systems that are used on these engines. The second approach for in-cylinder emissions reductions is similar in description at least to the Caterpillar ACERT technology which we believe could be another path for compliance with this standard. We are projecting a modest increase in heat-rejection to the engine coolant for these in-cylinder emission control solutions and have accounted for those costs in our cost analysis. These approaches for NO_X reduction have been proven for on-highway diesel engines since 2003 including compliance with NTE provisions similar to those for nonroad engines finalized here. We can conclude based on the on-highway experience that the NTE provisions can be met for engines in this horsepower category. One commenter suggested that a standard of 3.5 g/bhp-hr would be achievable in this time frame. As described here, we believe that further emission reductions to 2.6 g/bhp-hr are possible in this time frame. Engine manufacturers have indicated to the Agency that they believe this level of in-cylinder emission control can be realized for these very large diesel engines by 2011. We are deferring any decision on setting aftertreatment based NO_X standards for mobile machinery above 750 hp to allow additional time to evaluate the technical issues involved, as discussed in section II.A.4.

NMHC Standards. We are setting two different NMHC emission standards for engines in this category linked to the technologies used to control PM emissions. We are requiring all engines over 750 hp to meet an NMHC standard of 0.30 g/bhp-hr starting in 2011. As explained earlier, in 2011 all engines over 750 hp must meet a PM emission standard of 0.075 g/bhp-hr. We are projecting that manufacturers will meet this standard through improvements in in-cylinder emission control of PM (in conjunction with use of 15 ppm sulfur diesel fuel). These PM control technologies, increased fuel injection

[50] Emerachem EMx™ Datasheet—Describing the EMx IC (Internal Combustion) System Air Docket OAR–2003–0012–0948.

[51] See for example 68 FR 28375, May 23, 2003.

[52] Fleetguard StableGuard™ Urea Premix for use with SCR NO_X Reduction Systems, Air Docket A–2001–28 Item IV–A–04.

pressure, improved electronic controls and enhanced combustion system designs will concurrently lower NMHC emissions to the NMHC standard of 0.30 g/bhp-hr.

The second step in our NMHC standards is to a level of 0.14 g/bhp-hr, consistent with the standard for on-highway diesels beginning in 2007 and for other nonroad diesel engines from 75 to 750 hp beginning in 2011. This change in NMHC standards is timed to coincide with the requirement that engines over 750 hp meet stringent PM emission standards that we believe will require the use of catalyst-based diesel particulate filter systems. These systems are expected to incorporate oxidation catalyst functions to control the SOF portion of diesel PM and to promote robust soot regeneration within the filter. This same oxidation function is highly effective at controlling NMHC emissions (the RIA documents reductions of more than 80 percent) and will result in a reduction in NMHC emissions below the 0.14 g/bhp-hr standard for these engines. As the high level of NMHC control afforded by the application of this technology is broadly realized across the wide range of diesel engine operation, it will allow for compliance with the NTE provisions as well. Although in practice we expect that NMHC emissions may be lower than the 0.14 g/bhp-hr standard, we have not finalized a more stringent standard for NMHC in order to maintain consistency with the NMHC standard we are finalizing for engines from 75 hp to 750 hp, for which the NMHC standard is in part based on feasibility considerations for NO_X adsorber catalyst systems that use diesel fuel to regenerate themselves (with consequent increased NMHC emissions during regeneration events). We believe this is appropriate considering our expectation that NO_X adsorber technology will be found feasible for all nonroad engines over 750 hp.

4. Are the New Tier 4 Standards for Engines 25–75 hp Feasible?

As discussed in section II.B, our standards for 25–75 hp engines consist of a 2008 transitional standard and long-term 2013 standards. The transitional standard is a 0.22 g/bhp-hr PM standard. The 2013 standards consist of a 0.02 g/bhp-hr PM standard and a 3.5 g/bhp-hr NMHC+NO_X standard.[53] As discussed in section II.A, the transitional standard is optional for 50–75 hp engines, as the 2008 implementation date is the same as the effective date of the Tier 3 standards. Manufacturers may decide, at their option, not to undertake the 2008 transitional PM standard, in which case their implementation date for the 0.02 g/bhp-hr PM standard begins in 2012. The remainder of this section discusses what makes the 25–75 hp category unique and why the standards are technologically feasible.

a. What Makes the 25–75 hp Category Unique?

As EPA explained in the proposal, and as discussed in section II.A, one cannot assume that highway technologies are automatically transferable to 25–75 hp nonroad engines. In contrast with 75–750 hp engines, which share similarities in displacement, aspiration, fuel systems, and electronic controls with highway diesel engines, engines in the 25–75 hp category have a number of technology differences from the larger engines. These include a higher percentage of indirect-injection fuel systems, and a low fraction of turbocharged engines (see generally RIA chapter 4.1). The distinction in the under 25 hp category is even more pronounced, with no turbocharged engines, nearly one-fifth of the engines have two cylinders or less, and a significant majority of the engines have indirect-injection fuel systems.

The distinction is particularly marked with respect to electronically controlled fuel systems. These are commonly available in the power categories greater than or equal to 75 hp, but, based on the available certification data as well as our discussions with engine manufacturers, we believe there are very limited numbers, if any, in the 25–75 hp category (and no electronic fuel systems in the less than 25 hp category). The research and development work being performed today for the heavy-duty highway market is targeted at engines which are 4-cylinders or more, direct-injection, electronically controlled, turbocharged, and with per-cylinder displacements greater than 0.5 liters. As discussed in more detail below, as well as in section II.B.5 (regarding the under 25 hp category), these engine distinctions are important from a technology perspective and warrant a different set of standards for the 25–75 hp category (as well as for the under 25 hp category).

b. Are the New Tier 4 Standards for 25–75 hp Engines Technologically Feasible?

This section will discuss the technical feasibility of both the interim 2008 PM standard and the 2013 standards. For an explanation and discussion of the implementation dates, please refer to section II.A.

i. 2008 PM Standards[54]

We are today finalizing the interim PM control program as proposed for engines in the power category from 25–75 hp. The new PM standard for 2008 is 0.22 g/bhp-hr over the appropriate steady-state test cycle (the NRTC and NTE do not apply, for the reasons explained below).[55] The standard is premised on the use of 500 ppm sulfur diesel fuel and the potential for improvements in engine-out emission control where possible or the application of a diesel oxidation catalyst (DOC). Some commenters raised concerns that this level of emission control from diesel engines may not be possible in 2008 without fuel cleaner than 500 ppm or without changes in the Tier 3 NMHC+NO_X emission standards. Other commenters, including some engine manufacturers, supported this interim program. As explained in the following sections, we continue to believe that these standards are appropriate and feasible in the leadtime provided.

Engines in the 25–50 hp category must meet Tier 2 NMHC+NO_X and PM standards today. We have examined the model year 2004 engine certification data for engines in the 25–50 hp category. These data indicate that over 35 percent of the engine families meet the 2008 0.22 g/bhp-hr PM standard and 5.6 g/bhp-hr NMHC+NO_X standard (unchanged from Tier 2 in 2008) today (even without 500 ppm sulfur diesel fuel). At the time of the proposal, we had analyzed model year 2002 data for this power range, which at that time indicated approximately 10 percent of the engine families complied with the 2008 requirements. The most recent data for model year 2004 indicates substantial progress has already been made in just the past few year in lowering emissions from these engines. This is primarily due to the implementation of the Tier 2 standards in model year 2004. The model year

[53] The 2013 NO_X+NMHC standard is a new standard only for engines in the 25–50 hp category. For engines in the 50–75 hp category, 3.5 g/bhp-hr NO_X+NMHC is the existing Tier 3 emission standard which will now also apply across the new regulated test cycles (*e.g.*, NRTC).

[54] As discussed in section II.B., manufacturers can choose, at their option, to pull-ahead the 2013 PM standard for the 50–75 hp engines to 2012, in which case they do not need to comply with the transitional 2008 PM standard.

[55] However, a manufacturer can choose to comply over the TRU cycle including the associated NTE provisions. Compliance with the NTE for engines selecting to certify on the TRU cycle is straightforward because by the very nature of the products, their operation is directly limited to a small range of operating modes over which compliance with the emission standard has already been shown.

2001 certification data also showed the 2008 standard were achievable using a mix of engine technologies (IDI and DI, turbocharged and naturally aspirated) tested on a variety of certification test cycles.[56] A detailed discussion of these data is contained in the RIA.

At the time of the proposal, no certification data was available for engines in the 50–75 hp range, because those engines were not subject to a Tier 1 standard and were not subject to Tier 2 standards until model year 2004. We have now had an opportunity to analyze the model year 2004 certification data for engines in the 50–75 hp range. These data shows that more than 70 percent of the engine families in this power range are capable of meeting the 2008 PM standards today. However, most of these engines do not yet meet the 3.5 g/bhp-hr Tier 3 NMHC+NO_X standard, which is required in 2008. We expect that to comply with the Tier 3 standards, these engines will use technologies such as EGR and electronically controlled fuel injection systems (and we included the costs of these technologies in assessing the costs of the Tier 3 standards). These technologies have been shown to reduce NO_X emissions by 50 percent without increasing PM emissions. The certification data show that for the 70 percent of the engine families which meet the 2008 Tier 4 PM standard (0.22 g/bhp-hr), a NO_X reduction of less than 50 percent is needed for most of these engines to meet the 2008 Tier 4 NMHC+NO_X standard. A detailed discussion of these data is contained in the RIA.

In addition to using known engine-out techniques, we also project that the 2008 standards can be achieved with the use of DOCs. DOCs are passive flow-through emission control devices which are typically coated with a precious metal or a base-metal washcoat. DOCs have been proven to be durable in use on both light-duty and heavy-duty diesel applications. In addition, DOCs have already been used to control carbon monoxide on some nonroad applications.[57] Some commenters raised concerns that DOCs could actually increase PM emissions when used on 500 ppm sulfur diesel fuel due to the potential for oxidation of the sulfur in the fuel to sulfate PM. While we agree with the commenters that sulfur reductions are important to control PM and in the long term that a 15 ppm fuel sulfur level will be the best solution, we disagree with the assertion that the amount of sulfate PM formed from a DOC will be such that compliance with the 0.22 g/bhp-hr standard will be infeasible. While commenters shared data showing increased PM emissions when DOCs are used, we have similarly found data (included in the RIA) that shows an overall reduction in emissions. To understand this discrepancy, it is important to realize that DOCs can be designed for operation on a range of fuel sulfur levels. The lower the fuel sulfur level, the more effective the PM oxidation function, but even at 500 ppm sulfur a properly designed DOC will realize a net reduction in PM emissions. DOCs have been successfully applied to diesel engines for on-highway applications for PM control on 500 ppm fuel since 1994 through careful design of the DOC trading-off PM reduction potential and sulfur oxidation potential. The RIA contains additional analysis describing DOC function, and its expected effectiveness when applied to nonroad diesel engines.

Other commenters argued that the application of DOC to diesel engines in this category would lead to an even greater emission reduction than estimated in our proposal, thus allowing the Agency to finalize a lower PM standard. While we agree that some engines will have lower emissions than required to meet the standard and that in the long term (once 15 ppm fuel is widely available) the PM emissions will be further reduced, we do not believe that an emission level lower than 0.22 g/bhp-hr will be generally feasible in 2008 due to the sulfur level of diesel fuel of 500 ppm sulfur and the potential for sulfate PM formation.

In summary then, there are two likely means by which companies can comply with the interim 2008 PM standard. First, engine manufacturers can comply with this standard using known engine-out techniques (*e.g.*, optimizing combustion chamber designs, fuel-injection strategies). In fact, some fraction of engines already would comply with the emission standard. In addition, some engine manufacturers may choose to use diesel oxidation catalysts to meet this standard. Our cost analysis makes the conservative assumption (*i.e.*, the higher cost assumption) that all manufacturers will use DOC catalysts to comply with these emission standards.

Based on the existence of a number of engine families which already comply with the 0.22 g/bhp-hr PM standard (and the 2008 NMHC+NO_X standard), and the availability of well known PM reduction technologies such as engine-out improvements and diesel oxidation catalysts, we project that the 0.22 g/bhp-hr PM standards is technologically feasible by model year 2008.

ii. 2013 Standards

For engines in the 25–50 range, we are finalizing standards commencing in 2013 of 3.5 g/bhp-hr for NMHC+NO_X and 0.02 g/bhp-hr for PM. For the 50–75 hp engines, we are finalizing a 0.02 g/bhp-hr PM standard which will be implemented in 2013, and for those manufacturers who choose to pull-ahead the standard one-year, 2012 (manufacturers who choose to pull-ahead the 2013 standard for engines in the 50–75 range do not need to comply with the transitional 2008 PM standard). A more complete discussion of the options available to manufacturers and the nature of the transitional program can be found in section II.A. These standards are measured using the NRTC and steady-state tests. These engines also will be subject to the NTE starting with the 2013 model year.

PM Standard. For engines in the horsepower category from 25–75 hp, we are finalizing a PM standard of 0.02 g/bhp-hr based on the application of catalyzed diesel particulate filters to engines in this category. We received a wide range of comments on our proposal with some arguing that the emission standard could be met earlier than 2013 and others arguing that while technically possible to apply PM filters to engines in this category, that it was not economically or otherwise practical to do so.

The RIA discusses in detail catalyzed diesel particulate filters, including explanations of how CDPFs reduce PM emissions, and how to apply CDPFs to nonroad engines. We have concluded, as explained above, that CDPFs can be used to achieve the 0.01 g/bhp-hr PM standard for 75–750 hp engines. As also discussed in section II.B.2.a above, PM filters will require active back-up regeneration systems for many nonroad applications above and below 75 hp because low temperature operation is an issue across all power categories. One commenter raised concerns regarding the low exhaust temperatures possibly experienced by small nonroad engines and argued that such low temperatures make PM filter regeneration impossible absent the use of active regeneration technologies. We agree with the commenter that active regeneration, as described previously, may be necessary and have included the cost for such

[56] The Tier 1 and Tier 2 standards for this power category must be demonstrated on one of a variety of different engine test cycles. The appropriate test cycle is selected by the engine manufacturer based on the intended in-use application of the engine.

[57] EPA Memorandum "Documentation of the Availability of Diesel Oxidation Catalysts on Current Production Nonroad Diesel Equipment," William Charmley. Copy available in EPA Air Docket A–2001–28 Item II–B–15.

systems in our cost estimates. See section II.B.1.a. A number of secondary technologies are likely required to enable proper regeneration, including possibly electronic fuel systems such as common rail systems which are capable of multiple post-injections which can be used to raise exhaust gas temperatures to aid in filter regeneration.

Particulate filter technology, with the requisite trap regeneration technology, can also be applied to engines in the 25 to 75 hp range. As explained earlier, the fundamentals of how a filter is able to reduce PM emissions are not a function of engine power, so that CDPF's are just as effective at capturing soot emissions and oxidizing SOF on smaller engines as on larger engines. The PM filter regeneration systems described in section II.B.2 are also applicable to engines in this size range and are likewise feasible. There are specific trap regeneration technologies which we believe engine manufacturers in the 25–75 hp category may prefer over others. For example, some manufacturers may choose to apply an electronically-controlled secondary fuel injection system (*i.e.*, a system which injects fuel into the exhaust upstream of a PM filter). Such a system has been commercially used successfully by at least one nonroad engine manufacturer, and other systems have been tested by technology companies.[58] However, we recognize that the application of these technologies will be challenging and will require additional time to develop. We therefore disagree with commenters who say that the standard could be met sooner and have decided to finalize the implementation schedule as proposed.

As we proposed, we are finalizing a slightly higher PM standard (0.02 g/bhp-hr rather than 0.01) for engines in this power category. As discussed in the preamble to the proposed rule and in some detail in the RIA, with the use of a CDPF, the PM emissions emitted by the filter are primarily derived from the fuel sulfur (68 FR 28389–28390, May 23, 2003). The smaller power category engines tend to have higher fuel consumption per unit of work than larger engines. This occurs for a number of reasons. First, the lower power categories include a high fraction of IDI engines which by their nature consume approximately 15 percent more fuel than a DI engine. Second, as engine displacements get smaller, the engine's combustion chamber surface-to-volume ratio increases. This leads to higher heat-transfer losses and therefore lower efficiency and higher fuel consumption. In addition, frictional losses are a higher percentage of total power for the smaller displacement engines which also results in higher fuel consumption. Because of the higher fuel consumption rate, we expect a higher particulate sulfate level, and therefore we have set a 0.02 g/bhp-hr standard for engines in this power category. We did not receive any comments on our proposal arguing that the technical basis for this higher PM level was inappropriate.

The 0.02 g/bhp-hr standard applies to all of the test cycles applicable to engines in this power category (*i.e.*, the NRTC including cold-start, the ISO C1, D2 and G2 cycles and the alternative TRU and RMC cycles, as appropriate). Our feasibility analysis summarized here and detailed in the RIA takes into consideration these different test cycles. The control technologies work in a similar manner and provide the same high level of emission control across these different operating regimes including the NTE. The most significant effect on emission performance is related to sulfate PM formation at high load, high temperature operating conditions. As the RIA details, this level of high sulfate formation rate is not high enough to preclude compliance with the PM emission standard with 15 ppm fuel sulfur on the regulated test cycles nor is it high enough to preclude compliance with the NTE provisions. At higher fuel sulfur levels however, compliance with the PM emission standard would not be feasible.

The majority of negative comments on our proposal to set a PM standard based on the control possible from PM filter technologies focused on the economic and technical challenges to apply these technologies and the major engine technology enabler, electronic fuel systems, to smaller diesel engines. Some commenters acknowledged that the technologies were "technically feasible" but not economically feasible or practical for engines in this power category. While we acknowledge that the application of these technologies to diesel engines in this horsepower category will be challenging and have given consideration to this in setting the timing for the new standard, we believe that the technical path for compliance is clear and that the cost estimates we have made for these engines accurately represent this technical path. As discussed in the RIA, at the time of the proposal we projected no significant penetration of electronic fuel systems for engines in the 50–100 hp range prior to the Tier 3 standards (2008). Since the proposal, new information regarding model year 2004 engine certifications has become available. That data show 18 percent of the engines in the 75–100 hp category already use electronically controlled fuel systems. In model year 2001, no engines in this category used electronic fuel systems. We believe this strong trend toward the introduction of more advanced electronic fuel system technology will continue in the future and, importantly for engines in the 25–75 hp category, will extend to ever smaller engine categories due to the user benefits provided by the technology and the falling cost for such systems. However, acknowledging the substantial time between now and 2012, and the potential for technologies to mature faster or slower than we are estimating here, we have decided to conduct a technology review of these standards as described in section II.A above. This review will provide EPA with another opportunity to confirm that the technical path laid out here is indeed progressing in a manner consistent with our expectations.

NMHC+NO_X Standard. As we proposed, we are finalizing a 3.5 g/bhp-hr NMHC+NO_X standard for engines in the 25–50 hp range for 2013. We received limited comments arguing that the NMHC+NO_X standard should be less stringent. Like the PM standard, some commenters argued that the NO_X standard would be costly and complicated, although not necessarily infeasible to apply. Other commenters argued that the NO_X standard for engines in this category like the new standard for larger engines, should be based upon the application of advanced NO_X catalyst-based technologies. As described previously in section II.A, we do not believe that the catalyst-based NO_X technologies have matured to a state were we can accurately define a feasible technical path for compliance for engines in this power category. We intend to revisit this question in our technology review and if we find that a viable technical path can be described we will consider the appropriateness of a more stringent catalyst-based standard.

The new standard aligns the NMHC+NO_X standard for engines in this power range with the Tier 3 standard for engines in the 50–75 hp range which are implemented in 2008. EPA's recent Staff Technical paper which reviewed the technological feasibility of the Tier 3 standards contains a detailed discussion of a number of technologies which are capable of achieving a 3.5 g/bhp-hr standard. These include cooled EGR, uncooled EGR, as well as advanced in-

[58] "The Optimized Deutz Service Diesel Particulate Filter System II," H. Houben *et. al.*, SAE Technical Paper 942264, 1994 and "Development of a Full-Flow Burner DPF System for Heavy Duty Diesel Engines," P. Zelenka *et. al.*, SAE Technical Paper 2002–01–2787, 2002.

cylinder technologies relying on electronic fuel systems and turbocharging.[59] These technologies are capable of reducing NO_X emissions by as much as 50 percent. Given the Tier 2 NMHC+NO_X standard of 5.6 g/bhp-hr, a 50 percent reduction would allow a Tier 2 engine to comply with the 3.5 g/bhp-hr NMHC+NO_X standard set in this action. Therefore, we are projecting that 3.5 g/bhp-hr NO_X+NMHC standard is feasible with the addition of cooled EGR (the basis for our cost analysis) or other equally effective in-cylinder NO_X control technology as described in the RIA and our recent Staff Technical Paper. In addition, because this NMHC+NO_X standard is concurrent with the 0.02 g/bhp-hr PM standards which we project will be achievable with the use of particulate filters, engine designers will have significant additional flexibility in reducing NO_X because the PM filter will lessen the traditional concerns with the engine-out NO_X vs. PM trade-off.

Our recent highway 2004 standard review rulemaking (see 65 FR 59896, October 2000) demonstrated that a diesel engine with advanced electronic fuel injection technology as well as NO_X control technology such as cooled EGR is capable of complying with an NTE standard set at 1.25 times the laboratory-based FTP standard. We project that the same technology (electronic fuel systems and cooled EGR) are also capable for engine in the 25–75 hp range of complying with the NTE standard of 4.4 g/bhp-hr NMHC+NO_X (1.25×3.5) in 2013. This is based on the broad NO_X reduction capability of cooled EGR technology, which is capable of reducing NO_X emissions across the engine operating map (including the NTE region) by at least 30 percent even under high load conditions.[60]

Based on the information available to EPA and presented here, and giving appropriate consideration to the lead time necessary to apply the technology as well, we have concluded the 0.02 g/bhp-hr PM standard for engines in the 25–75 hp category and the 3.5 g/bhp-hr NMHC+NO_X standards for the 25–50 hp engines are achievable.

5. Are the Standards for Engines Under 25 hp Feasible?

As we explained at proposal and as discussed in section II.A, the new PM standard for engines less than 25 hp is 0.30 g/bhp-hr beginning in 2008. The certification test cycle for this standard is the ISO C1 cycle (or other appropriate steady-state test as defined by the engine's intended use) from 2008 through 2012. Beginning in 2013, the NRTC (with cold-start) and the NTE will also apply to engines in this category. As discussed below, we are not setting a new standard more stringent than the existing Tier 2 NMHC+NO_X standard for this power category at this time. This section describes what makes the less than 25 hp category different and why the standards are technologically feasible.

a. What Makes the Under 25 hp Category Unique?

As we explained at proposal and in the RIA, nonroad engines less than 25 hp are the least sophisticated nonroad diesel engines from a technological perspective. All of the engines currently sold in this power category lack electronic fuel systems and turbochargers. Nearly 20 percent of the products have two-cylinders or less, and 14 percent of the engines sold in this category are single-cylinder products, a number of these have no batteries and are crank-start machines, much like today's simple walk behind lawnmower engines. In addition, given what we know today and taking into account the Tier 2 standards which have not yet been implemented, we are not projecting any significant penetration of advanced engine technology, such as electronically controlled fuel systems, into this category in the next 5 to 10 years.

b. What Data Indicate That the Standards Are Feasible?

We project the Tier 4 PM standard can be met by 2008 based on: The existence of a large number of engine families which meet the new standards today; the use of engine-out reduction techniques; and the use of diesel oxidation catalysts.

Engines in the less than 25 hp category must meet Tier 1 NMHC+NO_X and PM standards today. We have examined the 2004 model year engine certification data for nonroad diesel engines less than 25 hp. These data indicate that a number of engine families meet the new Tier 4 PM standard (and the 2008 NMHC+NO_X standard, unchanged from Tier 2) today. The data show that 31 percent of the engine families are at or below the PM standard today, while meeting the 2008 NMHC+NO_X standard. At the time of the proposal, we examined the model year 2002 certification, which indicated approximately 30 percent of the engine families were at or below the 2008 emission standards. This certification data includes both IDI and DI engines, as well as a range of certification test cycles.[61] Many of the engine families are certified well below the Tier 4 standard while meeting the 2008 NMHC+NO_X level. Specifically, for the model year 2002 data, 15 percent of the engine families are cleaner than the new Tier 4 PM standard by more than 20 percent. The public certification data indicate that these engines do not use turbocharging, electronic fuel systems, exhaust gas recirculation, or aftertreatment technologies. We saw little change between the model year 2002 and 2004 data for this power category primarily because both model years are subject to the Tier 1 standards, and many engine families are simply carried over from the previous model year. Tier 2 standards for these engines will not be implemented until model year 2005. A detailed discussion of these data is contained in the RIA.

In summary then, there are two likely means by which companies can comply with the 2008 PM standard for engines under 25 hp. First, engine manufacturers can comply with this standard using known engine-out techniques (*e.g.*, optimizing combustion chamber designs, fuel-injection strategies). In fact, some fraction of engines already would comply with the emission standard. In addition, some engine manufacturers may choose to use diesel oxidation catalysts to meet this standard. Our cost analysis makes the conservative assumption (*i.e.*, the higher cost assumption) that all manufacturers will use DOCs to comply with these emission standards.

As discussed in section II.A, we are finalizing supplemental test procedures and standards (nonroad transient test cycle and not-to-exceed requirements) for engines in the under 25 hp category beginning in 2013. The supplemental test procedures and standards will apply not only to PM, but also to NMHC+NO_X. The engine technologies necessary to comply with the supplemental test procedures and standards are the same as the technology necessary to comply with the 2008 standard, and we have given

[59] See section 2.2 through 2.3 in "Nonroad Diesel Emission Standards—Staff Technical Paper," EPA Publication EPA420–R–01–052, October 2001. Copy available in EPA Air Docket A–2001–28.

[60] See section 8 of "Control of Emissions of Air Pollution from 2004 and Later Model Year Heavy-Duty Highway Engines and Vehicles: Response to Comments," EPA document EPA420–R–00–011, July 2000, and chapter 3 of "Regulatory Impact Analysis: Control of Emissions of Air Pollution from Highway Heavy-duty Engines," EPA document EPA420–R–00–010, July 2000. Copies of both documents available in EPA docket A–2001–28.

[61] The Tier 1 and Tier 2 standards for this power category must be demonstrated on one of a variety of different engine test cycles. The appropriate test cycle is selected by the engine manufacturer based on the intended in-use application(s) of the engine.

consideration to these test conditions in setting this standard. The range of operating conditions covered by the various test cycles and the mechanism for emission control over those ranges of operation are substantially similar allowing us to conclude that emission control will be substantially uniform across these test procedures. However, we are delaying the implementation of the supplemental test procedures and standards until 2013, as proposed, in order to implement these supplemental requirements on the larger powered nonroad engines before the smallest power category. (There were no adverse comments on this aspect of the proposed rule.) This will also provide engine manufacturers with additional time to install any emission testing equipment upgrades they may need in order to implement the new nonroad transient test cycle.

Based on the existence of a number of engine families which already comply with the new Tier 4 PM standard (and the 2008 NMHC+NO_X standard), and the availability of PM reduction technologies such as improved mechanical fuel systems, combustion chamber improvements, and in particular diesel oxidation catalysts, we project that the 0.30 g/bhp-hr PM standards is technologically feasible by model year 2008.

6. Meeting the Crankcase Emissions Requirements

The most common way to eliminate crankcase emissions has been to vent the blow-by gases into the engine air intake system, so that the gases can be recombusted. Prior to the HD2007 rulemaking, we have required that crankcase emissions be controlled only on naturally aspirated diesel engines. We had made an exception for turbocharged diesel engines (both highway and nonroad) because of concerns in the past about fouling that could occur by routing the diesel particulates (including engine oil) into the turbocharger and aftercooler. However, this is an environmentally significant exception since most nonroad equipment over 75 hp use turbocharged engines, and a single engine can emit over 100 pounds of NO_X, NMHC, and PM from the crankcase over its lifetime.

Given the available means to control crankcase emissions, we eliminated this exception for highway engines in 2007 and similarly in today's action are eliminating the exception for nonroad diesel engines as well. A number of commenters supported this provision noting that the necessary technologies are already in application in Europe and will be required for heavy-duty diesel trucks in the United States beginning in 2007.

We anticipate that the diesel engine manufacturers will be able to control crankcase emissions through the use of closed crankcase filtration systems or by routing unfiltered blow-by gases directly into the exhaust system upstream of the emission control equipment. However, the provisions have been written such that if adequate control can be had without "closing" the crankcase then the crankcase can remain "open." Compliance would be ensured by adding the emissions from the crankcase ventilation system to the emissions from the engine control system downstream of any emission control equipment. We have limited this provision for controlling emissions from open crankcases to turbocharged engines, which is the same as for heavy-duty highway diesel engines.

Some commenters in essence argued that the Agency was obligated to show that all potential compliance paths were feasible and absent that showing that the Agency should reconsider this provision. Our feasibility analysis is based on the use of closed crankcase technologies designed to filter crankcase gases sending the clean gas to the engine intake for combustion and returning the oil filtered from the gases to the engine crankcase. These systems are proven in use and the use of this technology to eliminate crankcase emissions is acceptable to demonstrate compliance. The other options, the option to vent crankcase emissions into the exhaust or to continue to vent crankcase emissions to the atmosphere provided the total emissions including tailpipe and crankcase emissions do not exceed the standards are provided as alternate solutions that are clearly effective to control emissions (*i.e.*, if the emissions are measured and are below the standard they are adequately controlled). The commenter suggests however, that they may not be able to control the emissions to the required level using these alternate approaches. In this case, a manufacturer would need to use the primary approach identified by EPA, closing the crankcase and routing the filtered gases to the engine's intake (this is the approach we used in the cost analysis summarized in section VI). We have allowed the alternative approaches at the recommendation of some in industry, because if they prove to be effective we accept that resulting total emissions will be acceptably low.

C. Why Do We Need 15 ppm Sulfur Diesel Fuel?

The new Tier 4 emission standards for most categories of nonroad diesel engines are predicated on the application of advanced diesel emission control technologies that are being developed for on-highway diesel engines to meet the HD2007 emission standards, namely catalyzed diesel particulate filters and NO_X adsorber catalysts. Sulfur in diesel fuel significantly impacts the durability, efficiency and cost of applying these technologies. Therefore, we required that on-highway diesel fuel produced for use in 2007 or newer on-highway diesel engines have sulfur content no higher than 15 ppm. Based on the same concerns outlined in the 2007 rulemaking, discussed in the proposal at 68 FR 28395–28400, set out in the RIA, and briefly summarized below, we today are finalizing a requirement that diesel fuel for nonroad engines be reduced to no higher than 15 ppm beginning in 2010. There was consensus among commenters that such standards were necessary if the proposed standards based on advanced diesel emission control technologies were to be achievable.

Sulfur in diesel fuel acts to poison the oxidation function of platinum-based catalysts including DOCs and CDPFs reducing the oxidation efficiency substantially, especially at lower temperatures. This poisoning limits the effectiveness of DOCs and CDPFs to oxidize CO and HC emissions. Of even greater concern is the reduction in NO oxidation efficiency of the CDPF due to sulfur poisoning. NO oxidation to NO_2 is a fundamental mechanism for PM filter regeneration necessary to ensure robust operation of the CDPF (*i.e.*, to prevent filter plugging). Sulfur poisoning from sulfur in diesel fuel at levels higher than 15 ppm has been shown to increase the likelihood of PM filter failure due to a depressed NO to NO_2 oxidation efficiency of the CDPF. The RIA documents substantial field experience in Europe regarding this phenomenon.

Sulfur in diesel fuel can itself be oxidized to form sulfate PM emitted into the environment. CDPFs in particular are designed for robust regeneration and are highly effective at oxidizing sulfur to sulfate PM (approaching 100 percent conversion under some circumstances). The sulfate PM emissions from a CDPF when operated on 350 ppm fuel can be so high as to actually increase the PM emission rate above the baseline level for an engine without a PM filter. In spite of more than ten years of research, no effective means has been found to provide the NO to NO_2 oxidation efficiency needed to ensure robust filter regeneration without similarly increasing efficiency to oxidize sulfur to sulfate PM. Conversely, technologies developed to suppress sulfate PM formation (*e.g.*, the addition of vanadium to DOCs designed to operate on 500 ppm sulfur fuel) also suppress NO to NO_2 formation. Therefore, it is not possible to apply the robust CDPF technology to achieve the PM standards without first having lower diesel fuel sulfur levels. The RIA documents substantial test data showing the impact of sulfur in diesel fuel on total PM emissions due to an increase in sulfate PM emissions.

Sulfur from diesel fuel likewise poisons the storage function of the NO_X adsorber catalyst. Sulfur in the exhaust in the form of SO_X is stored on the catalyst in the same way as the NO_X emissions are stored. Unfortunately, due to the chemical properties of the materials, the sulfur is stored preferentially to the NO_X and will actually displace the stored NO_X emissions. The stored sulfur is not easily removed from the catalyst. A sulfur removal step, called a desulfation, can be accomplished by raising exhaust temperatures to a very high level while simultaneously increasing the reductant content of the exhaust above the stoichiometric level (*i.e.*, more fuel than oxygen in the exhaust). This process can be effective to remove sulfur from the catalyst but at the expense of damaging the catalyst slightly. Over the lifetime of a diesel engine the cumulative damage from repeated desulfation events, as would be required if operation on higher than 15 ppm sulfur fuels were attempted, would lead to excessive damage and loss in NO_X control. The RIA contains an extensive description of this phenomena including the tradeoff between higher fuel sulfur levels and more frequent desulfation events.

The damage that sulfur inflicts on both the CDPF and NO_X adsorber technologies not only reduces their effectiveness but also impacts the fuel economy of their application. Reduced soot regeneration potential due to sulfur poisoning would lead to the need for more frequent active CDPF regeneration. As each active soot regeneration event consumes fuel, more frequent regeneration events with higher fuel sulfur levels leads to an increase in fuel consumption. Similarly, higher fuel sulfur levels would necessitate more frequent NO_X adsorber desulfation events and thus higher fuel consumption. An estimate of the impact of higher fuel sulfur levels on fuel economy due to more frequent desulfation events can be found in the RIA.

For all of the reasons documented in the RIA and summarized here, we remain convinced that a cap of 15 ppm fuel sulfur is necessary for both on-highway and nonroad diesel engines in order to apply the advanced emission control technologies necessary to meet the emission standards we are finalizing today.

III. Requirements for Engine and Equipment Manufacturers

This section describes the regulatory changes being made for the engine and equipment compliance program. A number of specific items are discussed in this section, including test procedures, certification fuels, and credit program provisions. These provisions are important in that they help us ensure the engines and equipment will meet the new requirements throughout their entire useful life, thus achieving the expected emission and public health benefits.

One of the most obvious changes from the Tier 2/Tier 3 program is that the regulations for Tier 4 engines have been written in a plain language format. They are structured to contain the provisions that are specific to nonroad compression ignition (CI) engines in a new part 1039, and to apply the general provisions of existing parts 1065 and 1068. The plain language regulations, however, are not intended to significantly change the compliance program, except as specifically noted in today's notice and supporting documents. These plain language regulations will only apply for Tier 4 engines. The changes from the existing nonroad program are described below along with other notable aspects of the compliance program.

As described below, we received comments from a broad range of commenters for some of these issues. For other issues, we received only manufacturer comments or no comments at all. See Chapter 9 of the Summary and Analysis of Comments for more information about the comments received and our responses to them.

A. Averaging, Banking, and Trading

1. Why Are We Adopting an ABT Program for Tier 4 Nonroad Diesel Engines?

EPA has included averaging, banking, and trading (ABT) programs in almost all of its recent mobile source emission control programs. Our existing regulations for nonroad diesel engines include an ABT program (40 CFR 89.201 through 89.212). With today's action we are retaining the basic structure of the existing nonroad diesel ABT program, though we are adopting a number of changes to accommodate implementation of the newly adopted Tier 4 emission standards. The ABT program is intended to enhance the ability of engine manufacturers to meet the stringent standards adopted today. The program is also structured to limit production of very high-emitting engines and to avoid unnecessary delay of the transition to the new exhaust emission control technologies.

We view the ABT program as an important element in setting emission standards that are appropriate under CAA section 213(a) with regard to technological feasibility, lead time, and cost, given the wide breadth and variety of engines covered by the standards. As we noted at proposal, if there are engine families that will be particularly costly or have a particularly hard time coming into compliance with the standard, this flexibility allows the manufacturer to adjust the compliance schedule accordingly, without special delays or exceptions having to be written into the rule. Emission-credit programs also create an incentive for the early introduction of new technology (for example, to generate credits in early years to create compliance flexibility for later engines), which allows certain engine families to act as trailblazers for new technology. This can help provide valuable information to manufacturers on the technology before they apply the technology throughout their product line. This early introduction of clean technology improves the feasibility of achieving the standards and can provide valuable information for use in other regulatory programs that may benefit from similar technologies. Early introduction of such engines also secures earlier emission benefits.

In an effort to make information on the ABT program more available to the public, we intend to issue an annual report summarizing use of the ABT program by engine manufacturers. The information contained in the reports will be based on the information submitted to us by engine manufacturers in their annual reports, and summarized in a way that protects the confidentiality of individual engine manufacturers. We believe this information will also be helpful to engine manufacturers by giving them a better indication of the availability of credits.

2. What Are the Provisions of the ABT Program?

The following section describes the ABT provisions being adopted with today's action. Areas in which we have made changes to the proposed ABT program are highlighted. A complete summary of comments received on the proposed ABT program and our response to those comments are contained in the Summary and Analysis of Comments document for this rule.

The ABT program has three main components. Averaging means the exchange of emission credits between engine families within a given engine manufacturer's product line. Engine manufacturers divide their product line into "engine families" that are comprised of engines expected to have similar emission characteristics throughout their useful life. Averaging allows a manufacturer to certify one or more engine families at levels above the applicable emission standard, but below a set upper limit. However, the increased emissions must be offset by one or more engine families within that manufacturer's product line that are certified below the same emission standard, such that the average emissions from all the manufacturer's engine families, weighted by engine power, regulatory useful life, and production volume, are at or below the level of the emission standard. (The inclusion of engine power, useful life, and production volume in the averaging calculations is designed to reflect differences in the in-use emissions from the engines.) Averaging results are calculated for each specific model year. The mechanism by which this is accomplished is certification of the engine family to a "family emission limit" (FEL) set by the manufacturer, which may be above or below the standard. An FEL that is established above the standard may not exceed an upper limit specified in the ABT regulations. Once an engine family is certified to an FEL, that FEL becomes the enforceable emissions limit for all the engines in that family for purposes of compliance testing. Averaging is allowed only between engine families in the same averaging set, as defined in the regulations.

Banking means the retention of emission credits by the engine manufacturer for use in future model year averaging or trading. Trading means the exchange of emission credits between nonroad diesel engine manufacturers which can then be used for averaging purposes, banked for future use, or traded to another engine manufacturer.

The existing ABT program for nonroad diesel engines covers $NMHC+NO_X$ emissions as well as PM emissions. With today's action and as proposed, we are making the ABT program available for the Tier 4 NO_X standards (and $NMHC+NO_X$ standards, where applicable) and the Tier 4 PM standards. As proposed, ABT will not be available for the Tier 4 NMHC standards for engines above 75 horsepower.

Engine manufacturers commented that ABT will most likely be necessary for the Tier 4 CO standards, given the reductions in PM and NO_X emissions. In the Tier 4 proposal, we proposed minor changes in CO standards for some engines solely for the purpose of helping to consolidate power categories and improving administrative efficiency. However, as noted earlier in section II.A.6, we have withdrawn this aspect of the proposal. We do note, however, that we are applying new certification tests to all pollutants covered by the rule, the result being that Tier 4 engines will have to certify to CO standards measured by the transient test (including a cold start component), and the NTE. However, as shown in RIA chapter 4.1.1.2 (see *e.g.*, note F), we believe that application of Tier 4 technologies will lead to a reduction in CO emissions over the Tier 3 baseline. We thus believe the CO standards will be readily achievable under the transient test and NTE. Moreover, we believe that there will not be any associated costs: The CO standards can be met without any further technological improvements (*i.e.*, improvements other than those already necessary to meet the Tier 4 standards) and these tests will already be used for certification. Since CO standards measured by the new certification tests are achievable without cost, there is no basis for allowing ABT because no additional lead time is needed.

As noted earlier, the existing ABT program for nonroad diesel engines includes FEL caps—limits on how high the emissions from credit-using engine families can be. No engine family may be certified above these FEL caps. These limits provide manufacturers with compliance flexibility while protecting against the introduction of unnecessarily high-emitting engines. In the past, we have generally set the FEL caps at the emission levels allowed by the previous standard, unless there was some specific reason to do otherwise. With today's action, we are taking a different approach because the level of the standards being adopted for most engines are significantly lower than the current level of the standards. The transfer to new technology is feasible and appropriate. Thus, as proposed, to ensure that the ABT provisions are not used to continue unnecessarily to produce old-technology high-emitting engines under the new program, the FEL caps are not, in general, set at the previous standards. Exceptions have been made for the $NMHC+NO_X$ standard for engines between 25 and 50 horsepower effective in model year 2013 and the NO_X standards applicable to engines above 750 horsepower in 2011, where we are using the estimated NO_X-only equivalent for the previously applicable $NMHC+NO_X$ standard for the FEL cap since the gap between the previous and newly adopted standards is approximately 40 percent (rather than 90 percent for engines between 75 and 750 horsepower), and because the technology basis for these standards can be a form of engine-out control, like the previous tier standards. This approach of setting FEL caps at lower levels than the previously applicable standards is consistent with the level of the FEL limits set in the 2007 on-highway heavy-duty diesel engine program.

STAPPA/ALAPCO supported the proposed FEL caps. The Engine Manufacturers Association (EMA) commented that EPA should eliminate the FEL caps altogether. They believe FEL caps are unnecessary because the zero-sum requirement of ABT will ensure that there are no adverse emission impacts. Short of eliminating the FEL caps, they commented that EPA should set FEL caps at the level of the previous standards, not the more stringent levels proposed. With today's action, EPA is adopting the FEL caps as proposed, with some exceptions for engines above 750 horsepower (where we are adopting different standards than originally proposed) and for phase-in engines between 75 and 750 horsepower (where we have adopted an option for manufacturers to certify to alternative NO_X standards during the phase-in period). We continue to believe that it is important to ensure that technology turns over in a timely manner and that manufacturers do not continue producing large numbers of high-emitting, old technology engines once the Tier 4 standards become fully effective. (As noted below, however, we are adopting provisions that allow manufacturers to produce a limited number of 75 to 750 horsepower engines for a limited period that are certified with FELs as high as the previous tier of standards.) For the Tier 4 standards, where the standards are being reduced by an order of magnitude, we believe this goal to be particularly important, and in keeping with the technology-forcing provisions of section 213(a). It simply would not be appropriate to have long-term FEL caps that allowed engines to indefinitely have emissions as high as ten times the level of the standard.

For engines between 75 and 750 horsepower certified using the phase-in/ phase-out approach, there will be two separate sets of engines with different FEL caps. For engines certified to the existing (Tier 3) NMHC+NO_X standards during the NO_X phase-in (referred to generally as "phase-out" engines), the FEL cap for these pollutants will (almost necessarily) be the existing FEL caps adopted in the October 1998 Tier 3 rule. For engines certified to the newly adopted Tier 4 NO_X standard during the phase-in (referred to generally as "phase-in" engines), we have revised the proposed FEL cap to be 0.60 g/bhp-hr, consistent with the proposed long-term Tier 4 NO_X FEL cap. As described in section II.A.2.c above, we have used the creation of alternative NO_X standards for engines between 75 and 750 horsepower to restate the phase-in/ phase-out concept as a path truly focused on achieving high-efficiency NO_X aftertreatment during the phase-in years. Setting the NO_X FEL cap at 0.60 g/bhp-hr for phase-in engines will ensure this happens if a manufacturer chooses to certify to the phase-in provisions. In contrast, the higher FEL caps which we proposed (see 68 FR 28467–28468) would not have achieved this objective.

Beginning in model year 2014 when the Tier 4 NO_X standards for engines between 75 and 750 horsepower take full effect, we are adopting a NO_X FEL cap of 0.60 g/bhp-hr for all engines. We reiterate that given the fact that the Tier 4 NO_X standard is approximately a 90 percent reduction from the existing standards for engines between 75 and 750 horsepower, we do not believe the previous standard is appropriate as the FEL cap for engines having to comply with the Tier 4 NO_X standard of 0.30 g/ bhp-hr. We believe that the NO_X FEL caps will ensure that manufacturers adopt NO_X aftertreatment technology across all of their engine designs.

For the interim PM standards for engines between 25 and 75 horsepower effective in model year 2008 and for the Tier 4 PM standards for engines below 25 horsepower, we are adopting the previously applicable Tier 2 PM standards for the FEL caps (which do vary within the 25 to 75 horsepower category) because the gap between the previous standards and the newly adopted standards is approximately 50 percent (rather than in excess of 90 percent for engines between 75 and 750 horsepower), and the technology basis for the 2008 PM standards can be a form of engine-out control, like the previous tier standard. For the Tier 4 PM standard effective in model year 2013 for engines between 25 and 75 horsepower, we are adopting a PM FEL cap of 0.04 g/bhp-hr, and for the Tier 4 PM standard effective in model years 2011 and 2012 for engines between 75 and 750 horsepower, we are adopting a PM FEL cap of 0.03 g/bhp-hr. As with the Tier 4 NO_X standards for these engines, given the fact that these Tier 4 aftertreatment-based PM standards for engines between 25 and 750 horsepower are over 90 per cent more stringent than the previous standards, we do not believe the previous standards are appropriate as FEL caps once the Tier 4 standards take effect. We believe that the newly adopted PM FEL caps will ensure that manufacturers adopt PM aftertreatment technology across all of their engine designs (except for a limited number of engines), yet will still provide substantial flexibility in meeting the standards.

The final Tier 4 standards for engines above 750 horsepower have been revised from the proposal. We similarly revised a number of the proposed ABT provisions for engines above 750 horsepower. Beginning in 2011, all engines above 750 horsepower will be required to meet a NO_X standard of 2.6 g/bhp-hr, except for those above 1200 horsepower used in generator sets which will be required to meet a NO_X standard of 0.50 g/bhp-hr. The NO_X FEL cap for the 2011 standards will be 4.6 g/bhp-hr, which is an estimate of the NO_X emissions level that is expected under the combined NMHC+NO_X standards that apply with the previously applicable tier for engines above 750 horsepower. Beginning in 2011, all engines above 750 horsepower will have to meet a PM standard of 0.075 g/bhp-hr. The PM FEL cap for the 2011 PM standard will be the previously-applicable Tier 2 standard of 0.15 g/ bhp-hr. As noted above, because the 2011 NO_X and PM standards are approximately 50 percent lower than the previous standard (rather than in excess of 90 percent for engines between 75 and 750 horsepower), and for most engines are based on performance of the same type of technology (engine-out), we are adopting the previously applicable Tier 2 standards for the FEL caps.

Beginning in model year 2015, the 0.50 g/bhp-hr NO_X standard will apply to all engines above 750 horsepower used in generator sets. Beginning in model year 2015, the PM standard drops to 0.02 g/bhp-hr for engines greater than 750 horsepower used in generator sets and 0.03 g/bhp-hr for engines greater than 750 horsepower used in other machines. Consistent with the Tier 4 FEL caps for lower horsepower categories where the new standards are significantly lower than the previously applicable standards and reflect performance of aftertreatment technology, we are adopting a NO_X FEL cap of 0.80 g/bhp-hr for engines used in generator sets and PM FEL caps of 0.04 g/bhp-hr for engines used in generator sets and 0.05 g/bhp-hr for engines used in other machines (*i.e.*, mobile machines). We believe that the FEL caps for engines above 750 horsepower will ensure that manufacturers adopt PM aftertreament technology across all of their engine designs and NO_X aftertreatment for generator sets once the 2015 standards are adopted, while allowing for some meaningful use of averaging beginning in 2015.

Table III.A–1 contains the FEL caps and the effective model year for the FEL caps (along with the associated standards adopted for Tier 4). It should be noted that for Tier 4, where we are adopting a new transient test for most engines, as well as retaining the current steady-state test, the FEL established by the engine manufacturer will be used as the enforceable limit for the purpose of compliance testing under both test cycles. In addition, under the NTE requirements, the FEL times the appropriate multiplier will be used as the enforceable limit for the purpose of such compliance testing. This is consistent with how FELs are used for compliance purposes in the 2007 on-highway heavy-duty diesel engine program.

TABLE III.A–1.—FEL CAPS FOR THE TIER 4 STANDARDS IN THE ABT PROGRAM (G/BHP-HR)

Power category	Effective model year	NO_X standard	NO_X FEL cap	PM standard	PM FEL cap
hp <25 (kW <19)	2008+	[a] 5.6	7.8 [a] for <11hp 7.1 [a] for >11hp	[c] 0.30	0.60
25 ≤ hp < 50 (19 ≤ kW <37)	2008–2012	[a] 5.6	7.1 [a]	0.22	0.45
25 ≤ hp < 50 (19 ≤ kW <37)	2013+	[b] 3.5	5.6 [b]	0.02	[f] 0.04
50 ≤ hp < 75 (37 ≤ kW <56)	2008–2012 [d]	[a] 3.5	5.6 [a]	0.22	0.30
50 ≤ hp < 75 (37 ≤ kW <56)	2013+ [e]	[a] 3.5	5.6 [a]	0.02	[f] 0.04
75 ≤ hp < 175 (56 ≤ kW <130)	2012+	0.30	0.60 [f g h]	0.01	[f] 0.03
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	2011+	0.30	0.60 [f g h]	0.01	[f] 0.03
hp > 750 (kW >560)	2011–2014	2.6 [i] 0.50	4.6 4.6	0.075	0.15
Generator Sets hp > 750 (kW >560)	2015+	0.50	0.80 [f]	0.02	[f] 0.04
Other Machines hp > 750 (kW >560)	2015+	[j] 2.6	4.6 [j]	0.03	[f] 0.05

Notes:

[a] These are the previous tier NMHC+NO_X standards and FEL caps. These levels are not being revised with today's rule and are printed here solely for readers' convenience.

[b] These are a combined NMHC+NO_X standard and FEL cap.

[c] A manufacturer may delay implementation until 2010 and then comply with a PM standard of 0.45 g/bhp-hr for air-cooled, hand-startable, direct injection engines under 11 horsepower.

[d] These FEL caps do not apply if the manufacturer opts out of the 2008 standards. In such cases, the existing Tier 3 standards and FEL caps continue to apply.

[e] The FEL caps apply in model year 2012 if the manufacturer opts out of the 2008 standards.

[f] As described in this section, a small number of engines are allowed to exceed these FEL caps.

[g] For engines certified as phase-out engines, the NMHC+NO_X FEL caps for the Tier 3 standards apply.

[h] For engines certified to the alternative NO_X standards during the phase-in, the NO_X FEL caps shown in tables III.A–3 and III.A–4 apply.

[i] The 0.50 g/bhp-hr NO_X standard applies only to engines above 1200 horsepower used in generator sets.

[j] The 2011 NO_X standard and FEL cap continue to apply unless and until revised by EPA in a future action.

As noted above, we are allowing a limited number of engines to have a higher FEL than the caps noted in Table III.A–1 in certain instances. The FEL cap for such engines would be set based on the level of the standards that applied in the year prior to the new standards and will allow manufacturers to produce a limited number of engines certified to these earlier standards in the Tier 4 timeframe. The allowance to certify up to these higher FEL caps will apply to Tier 4 engines between 25 and 750 horsepower beginning as early as the 2011 model year, and will apply to engines above 750 horsepower starting with the 2015 model year. The provisions are intended to provide some limited flexibility for engine manufacturers as they make the transition to the aftertreatment-based Tier 4 standards while ensuring that the vast majority of engines are converted to the advanced low-emission technologies expected under the Tier 4 program.

Under the proposal, manufacturers would have been allowed to certify at levels up to these FEL caps for ten percent of its engines in each of the first four years after the Tier 4 standards took effect and then five percent for subsequent years. The California Air Resources Board supported the proposed allowance. The Engine Manufacturers Association commented that the percentages of engines allowed to the higher FEL caps may not be sufficient, noting that it is too early to tell if the proposed amounts provided enough flexibility.

In an effort to provide flexibility to engine manufacturers while preserving the effective number of engines allowed to certify at levels up to the higher FEL caps, we are revising the proposed provisions with today's action. The revised provisions are intended to allow manufacturers to produce the same number of engines certified to the higher FEL caps as would have been allowed under the proposal, but provide added flexibility in how they distribute the allowances over the first four years of the transition to the new standards. This additional lead time appears appropriate, given the potential that a limited set of nonroad engines may face especially challenging compliance difficulties. Under the provisions adopted today and subject to the limitations explained below, a manufacturer would be allowed to certify up to 40 percent of its engines above the FEL caps shown in Table III.A–1 over the first four years the aftertreatment-based Tier 4 standards take effect (calculated as a cumulative total of the percent of engines exceeding these FEL caps in each year over the four years), with a maximum of 20 percent allowed in any given year (provided the FELs for these engines do not exceed levels specified below). During this four year period, manufacturers would not be required to perform transient testing or NTE testing on these engines because we expect these engines would be carried over directly from the previous tier without any modification. (NTE testing would apply to engines above 750 horsepower because the previously applicable set of standards required NTE testing.) Similarly, for engines between 75 and 750 horsepower, manufacturers would not be required to have closed crankcase controls on these engines because we also expect that these engines would be carried over directly from the previous tier without any modification. (Engines between 25 and 75 horsepower, and engines above 750 horsepower, would be required to have closed crankcase controls because the previously applicable set of standards require closed crankcase controls.)

For the purpose of calculating the number of credits such engines would use, the manufacturer would include an adjustment to the FEL to be used in the credit calculation equation. The adjustment would be included by multiplying the steady-state FEL by a Temporary Compliance Adjustment Factor (TCAF) of 1.5 for PM and 1.1 for NO_X. (The NO_X TCAF would not apply to engines that are not subject to the transient testing requirements for NO_X as discussed in section III.F.) We are adopting TCAFs in part to assure in-use control of emission from these engines in the absence of transient and NTE testing, and also to assure that any credits these engines use reflect the level of reductions expected in use. The level of the TCAFs are based on data from pre-control, Tier 1, and Tier 2 engines which show that the emissions from such engines tested over transient test cycles which are more representative of real in-use operation are higher than emissions from those engines tested over the steady-state certification test cycle. This is a sales weighted version of the Transient Adjustment Factor used in the NONROAD model. For compliance purposes, a manufacturer would be held accountable to the unadjusted steady-state FEL established for the engine family.

As proposed, after the fourth year the Tier 4 standards apply, the allowance to certify engines using the higher FEL caps shown in Table III.A–2 will still be available but for no more than five percent of the engines a manufacturer produces in each power category in a given year. When the 5 percent allowance takes effect, these engines will be considered Tier 4 engines and all other requirements for Tier 4 engines will also apply, including the Tier 4 NMHC standard, transient testing, NTE testing, and closed crankcase controls. TCAFs thus do not apply when calculating the number of credits such engines would use.

In the two power categories where we are adopting phase-in provisions (*i.e.*, 75 to 175 horsepower engines and 175 to 750 horsepower engines), the allowance to use a higher FEL cap will only apply to PM from phase-out engines during the phase-in years. We originally proposed that the allowance to use a higher FEL cap would apply to PM from either phase-in or phase-out engines during the phase-in years. On reflection, this is inconsistent with our policy that phase-in engines truly have low emissions reflecting use of aftertreatment (see also the discussion above where we explain that, for the same reason, we are adopting a NO_X FEL cap of 0.60 g/bhp-hr for phase-in engines). We consequently are revising the proposed allowance so that it is available for PM emissions only from phase-out engines. As proposed, the allowance to use a higher FEL cap for NO_X will apply starting in 2014 when the phase-in period is complete.

For the power category between 25 and 75 horsepower, this allowance to certify engines at levels up to the higher FEL caps will apply beginning with the Tier 4 standards taking effect in the 2013 model year and will apply to PM only. For manufacturers choosing to opt out of the 2008 model year Tier 4 standards for engines between 50 and 75 horsepower and instead comply with the Tier 4 standards beginning in 2012, the 40% allowance would apply to model years 2012 through 2015, and the 5% allowance would apply to model year 2016 and thereafter. The allowance to use the higher FEL caps is not applicable for the 2008 standards or the 2013 NMHC+NO_X standards for these engines because the FEL caps for those standards already are set at the level of the standard which previously applied.

For engines above 750 horsepower, the allowance to certify a limited number of engines at levels up to the higher FEL caps would apply beginning in model year 2015. (As noted, this is because the FEL caps being adopted for the 2011 standards for engines above 750 horsepower are the previous tier PM standard and the NO_X-only equivalent of the previous tier standard.) For NO_X, the allowance to certify a limited number of engines above the FEL cap beginning in model year 2015 will apply only to engines used in generator sets. Engines used in other machines are still subject to the model year 2011 NO_X standard and FEL caps. For PM, the allowance to certify a limited number of engines above the FEL caps beginning in model year 2015 will apply to all engines above 750 horsepower.

Table III.A–2 presents the model years, percent of engines, and higher FEL caps that will apply under these allowances. As noted above, engines certified under these higher FEL caps during the first four years would not be required to perform transient testing or NTE testing and engines between 75 and 750 horsepower would not be required to have closed crankcase controls on these engines. However, as also noted earlier, beginning in the fifth year, when the 5 percent allowance takes effect, these engines will be considered Tier 4 engines and all other requirements for Tier 4 engines will also apply, including the Tier 4 NMHC standard, transient testing, NTE testing, and closed crankcase controls.

TABLE III.A–2.—ALLOWANCE FOR LIMITED USE OF AN FEL CAP HIGHER THAN THE TIER 4 FEL CAPS

Power category	Model years	Engines allowed to have higher FELs (%)	NO_X FEL cap (g/bhp-hr)	PM FEL cap (g/bhp-hr)
25 ≤ hp < 75	2013–2016 [a]	[b] 40	Not applicable	0.22
(19 ≤ kW < 56)	2017+ [a]	5		
75 ≤ hp < 175	2012–2015	[b] 40	3.3 [c] for hp <100	0.30 [d] for hp <100
(56 ≤ kW <130)	2016+	5	2.8 [c] for hp ≥100	0.22 [d] for hp ≥100
175 ≤ hp ≤ 750	2011–2014	[b] 40	2.8 [c]	0.15 [d]
(130 ≤ kW ≤ 560)	2015+	5		
>750 hp	2015–2018	[b c] 40	2.6	0.075
(>560 kW)	2019+	[e] 5	.	

[a] For manufacturers choosing to opt out of the 2008 model year Tier 4 standards for engines between 50 and 75 horsepower and instead comply with the Tier 4 standards beginning in 2012, the 40% allowance would apply to model years 2012 through 2015, and the 5% allowance would apply to model year 2016 and thereafter.

[b] Compliance with the 40% limit is determined by adding the percent of engines that have FELs above the FEL caps shown in Table III.A.–1 in each of the four years. A manufacturer may not have more than 20% of its engines exceed the FEL caps shown in Table III.A–1 in any model year in any power category.

[c] The allowance to certify to these higher NO_X FEL caps is not applicable during the phase-in period.

[d] These higher PM FEL caps are applicable to phase-out engines only during the phase-in period.

[e] The limits of 40% or 5% allowed to exceed the NO_X FEL cap would apply to engines used in generator sets only. (Engines >750 hp used in other machines are allowed to have an NO_X FEL as high as 4.6 g/bhp-hr.) The limits of 40% or 5% allowed to exceed the PM FEL cap would apply to all engines above 750 hp.

Under the Tier 4 program, there will be two different groups of 75–750 horsepower engines during the NO_X phase-in period. In one group ("phase-out engines"), engines will certify to the applicable Tier 3 NMHC+NO_X standard and will be subject to the NMHC+NO_X ABT restrictions and allowances previously established for Tier 3. In the other group ("phase-in engines"), engines will certify to the 0.30 g/bhp-hr NO_X standard, and will be subject to the restrictions and allowances in this program. Although engines in each group are certified to different standards, we are (as proposed) allowing manufacturers to transfer credits across these two groups of engines with the following adjustment to the amount of credits generated. Manufacturers will be able to use credits generated during the phase-out of engines subject to the Tier 3 NMHC+NO_X standard to average with engines subject to the 0.30 g/bhp-hr NO_X standard, but these credits will be subject to a 20 percent discount, the adjustment reflecting the NMHC contribution. Thus, each gram of NMHC+NO_X credits from the phase-out engines will be worth 0.8 grams of NO_X credits in the new ABT program. The ability to average credits between the two groups of engines will give manufacturers a greater opportunity to gain experience with the low-NO_X technologies before they are required to meet the final Tier 4 standards across their full production. The 20 percent discount will also apply, for the same reason, to all NMHC+NO_X credits used for averaging purposes with the NO_X standards for engines greater than 75 horsepower.

The California Air Resources Board supported the proposed discount of 20 percent on NMHC+NO_X credits used for NO_X compliance. The Engine Manufacturer's Association commented that we should eliminate the 20 percent "discount" on NMHC+NO_X credits used for NO_X compliance.

We disagree with the Engine Manufacturer's Association comments. As noted in the proposal, we have two main reasons for adopting this adjustment. First, the discounting addresses the fact that NMHC reductions can provide substantial NMHC+NO_X credits, which are then treated as though they were NO_X credits. For example, a 2010 model year 175 horsepower engine emitting at 2.7 g/bhp-hr NO_X and 0.3 g/bhp-hr NMHC meets the 3.0 g/bhp-hr NMHC+NO_X standard in that year, but gains no credits. In 2011, that engine, equipped with a PM trap to meet the new PM standard, will have very low NMHC emissions because of the trap, an emission reduction already accounted for in our assessment of the air quality benefit of this program. As a result, without substantially redesigning the engine to reduce NO_X or NMHC, the manufacturer could garner nearly 0.3 g/bhp-hr of NMHC+NO_X credit for each of these engines produced. Allowing these NMHC-derived credits to be used undiscounted to offset NO_X emissions on the phase-in engines in 2011 (for which each 0.1 g/bhp-hr of margin can make a huge difference in facilitating the design of engines to meet the 0.30 g/bhp-hr NO_X standard) would be inappropriate. Therefore, while we are reducing the value of credits earned from Tier 2/Tier 3 engines, the adjustment accounts for the NMHC fraction of the credits which we do not believe should be used to demonstrate compliance with the NO_X-only Tier 4 standards (such credits would be "windfalls" because they would necessarily occur by virtue of the technology needed to meet the PM standard) (68 FR 28469, May 23, 2003). Second, the discounting will work toward providing a small net environmental benefit from the ABT program, such that the more manufacturers use banked and averaged credits, the greater the potential emission reductions overall. Most basically, it is inherently reasonable, in using NO_X+NMHC reductions to show credit with a NO_X-only standard, to use only that portion which represents NO_X reductions. (Indeed, for this reason, terming the 20 per cent a "discount factor" is a misnomer; it apportions the NMHC fraction of the reduction.) As noted, this is further supported by the fact that the NMHC reductions for phase-out engines are not extra reductions above and beyond what would otherwise occur, and therefore don't warrant eligibility as credits.

We are adopting one additional restriction on the use of credits under the ABT program. For the Tier 4 standards, we proposed that manufacturers could only use credits generated from other Tier 4 engines or from engines certified to the previously applicable tier of standards (*i.e.*, Tier 2 for engines below 50 horsepower, Tier 3 for engines between 50 and 750 horsepower, and Tier 2 engines above 750 horsepower). This proposed restriction was similar to a restriction we currently have that prohibits the use of Tier 1 credits to demonstrate Tier 3 compliance. STAPPA/ALAPCO and the Natural Resources Defense Council supported the proposed approach that limited the use of previous-tier credits for Tier 4. The Engine Manufacturer's Association commented that by limiting the use of previous-tier credits, we are engaged in an unconstitutional taking because EPA had guaranteed in the previous Tier 2/Tier 3 rulemaking that such credits would not expire. We disagree that adopting a restriction on the use of the previous tier ABT credits is an unconstitutional taking. EPA did not, and could not, decide in the Tier 2/3 rulemaking that Tier 2/3 credits could be used to show compliance with some future standards that had not yet even been adopted. Thus, EPA in this rulemaking is not taking away something previously given. We are not revisiting the Tier 2/3 standards but establishing a new set of engine standards. In doing so, we necessarily must evaluate the provisions of previous rules and their potential impact on the future standards being considered. We are reasonably concerned that credits from engines certified to relatively high standards could be used to significantly delay the implementation of the final Tier 4 program and its benefits, resulting in a situation where the standards would no longer reflect the greatest degree of emission reduction available as required under section 213(a)(3) of the Clean Air Act, or would no longer be appropriate under section 213(a)(4) of the Clean Air Act. Therefore, with today's action, we are adopting the proposed provisions regarding the use of credits from previous tier engines, with one minor revision.

Under today's action, manufacturers may only use credits generated from other Tier 4 engines or from engines certified to the previously applicable tier of standards—except for engines between 50 and 75 horsepower. Because we are adopting Tier 4 standards that take effect as early as 2008 for those engines, the same year the previously-adopted Tier 3 standards are scheduled to take effect (see section II.A.1.a above), there is no possibility to earn credits against the Tier 3 standards for manufacturers that certify with the pull-ahead standards in 2008 for engines between 50 and 75 horsepower. Therefore, we will allow manufacturers to use credits from engines in the Tier 2 power category that includes 50 to 75 horsepower (*i.e.*, the 50 to 100 horsepower category) that are certified to the Tier 2 standards if they choose to demonstrate compliance with the pull-ahead Tier 4 standards in 2008 for engines between 50 and 75 horsepower. Manufacturers that do not choose to comply with the 2008 Tier 4 standards for engines between 50 and 75 horsepower and instead comply with the 2012 Tier 4 standards for such engines will not be allowed to use Tier 2 credits in Tier 4, but instead will be allowed to use Tier 3 credits as allowed under the standard provisions regarding use of previous-tier credits only for Tier 4 compliance demonstration.

With regard to other restrictions on the use of ABT credits, we are adopting one restriction on the use of credits across the 750 horsepower threshold. In previous rulemakings, EPA has defined "averaging sets" within which manufacturers may use credits under the ABT program. Credits may not be used outside of the averaging set in which they were generated. As described in section II.A.4 of today's action, we have revised the Tier 4 standards for engines above 750 horsepower. Because the standards for Tier 4 engines greater than 750 horsepower will not be based on the use of PM aftertreatment technology in 2011 or NO_X aftertreatment technology for all mobile machinery engines in 2015, we are adopting provisions that prevent manufacturers from using credits from model year 2011 and later model year engines greater than 750 horsepower to demonstrate compliance with engines below 750 horsepower. Without such a limit, we are concerned that manufacturers could use credits from such engines to significantly delay compliance with the numerically lower standards for engines below 750 horsepower. In addition, without such a limit, we are concerned that manufacturers could use credits from engines below 750 horsepower to delay implementation of aftertreatment technology for engines above 750 horsepower.

One engine manufacturer commented that EPA should include a barrier to trading credits across the 75 horsepower level. They cited concerns over the ability of manufacturers that produce a large range of engine sizes to use credits from high horsepower engines to offset emissions from their small horsepower engines. We are not adopting any averaging set restrictions for Tier 4 engines below 750 horsepower in today's action. In the current nonroad diesel ABT program, there are averaging set restrictions. The current averaging sets consist of engines less than 25 horsepower and engines greater than or equal to 25 horsepower. We adopted this restriction because of concerns over the ability of manufacturers to generate significant credits from the existing engines and use the credits to delay compliance with the newly adopted standards (63 FR 56977, October 23, 1998). We believe the Tier 4 standards for engines below 750 horsepower are sufficiently rigorous to limit the ability of manufacturers to generate significant credits from their engines. In addition, we believe the FEL caps being adopted today provide sufficient assurance that low-emissions technologies will be introduced in a timely manner. Therefore, we believe averaging can be allowed between all engine power categories below 750 horsepower without restriction effective with the Tier 4 standards. (It should be noted that the averaging set restriction placed on credits generated from Tier 2 and Tier 3 engines will continue to apply if they are used to demonstrate compliance for Tier 4 engines.)

EPA also proposed to allow engine manufacturers to demonstrate compliance with the NO_X phase-in requirements by certifying evenly split engine families at, or below, specified NO_X FELs (68 FR 28470, May 23, 2003). As described in section II.A.2.c above, EPA is revising the evenly split family provisions for the Tier 4 program and is now codifying them as alternative standards. (As described in section III.L, we also are adopting the proposed provisions allowing manufacturers to certify "split" engine families during the phase-in years.) Because the evenly split family provision has evolved into a set of alternative NO_X standards, we believe it is appropriate to allow manufacturers to use ABT for them. Table III.A–3 presents the FEL caps that will apply to engines certified to the alternative NO_X standards during the phase-in years. The FEL caps for these alternative standards have been set at levels reasonably close to the alternative standards and are intended to ensure sizeable emission reductions from the previously-applicable Tier 3 standards. (For engines between 75 and 175 horsepower certified under the reduced phase-in option, the FEL cap is the NO_X-only equivalent of the previously applicable NMHC+NO_X standards because the alternative standard is sufficiently close to the Tier 3 standard.)

TABLE III.A–3.—NO_X FEL CAPS FOR ENGINES CERTIFIED TO THE ALTERNATIVE NO_X STANDARDS

Power category	Alternative NO_X standard (g/bhp-hr)	NO_X FEL cap (g/bhp-hr)
50/50/100 phase-in option for 75 ≤ hp < 175 (56 ≤ kW <130)	1.7	2.2.
25/25/25/100 phase-in option for 75 ≤ hp < 175 (56 ≤ kW <130)	2.5	3.3 (for 75–100 hp). 2.8 (for 100–175 hp)
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	1.5	2.0.

Because we are allowing manufacturers to use ABT for demonstrating compliance with the alternative standards for engines between 75 and 750 horsepower, we are allowing manufacturers to exceed the FEL caps noted in table III.A–3 and include them in the count of engines allowed to exceed the FEL caps (*i.e.*, the 40 percent over the first four years the Tier 4 standards take effect as described earlier). Table III.A–4 presents the NO_X FEL caps that would apply to engines certified under the alternative standards (limited by the 40 percent cap over the first four years). The higher NO_X FEL caps are set at the estimated NO_X-only equivalent of the previous-tier NMHC+NO_X standards. For manufacturers certifying under the reduced phase-in (25 percent) option, because the FEL caps are the NO_X-only equivalent of the Tier 3 NMHC+NO_X standards, they may not exceed the FEL cap during the years the alternative standard applies.

TABLE III.A–4.—LIMITED-USE NO_X FEL CAPS UNDER THE ALTERNATIVE NO_X STANDARDS

Power category	Model years	NO_X FEL cap (g/bhp-hr)
50/50/100 phase-in option for 75 ≤ hp < 175[a] (56 ≤ kW <130)	2012–2013	3.3 for hp <100. 2.8 for hp ≥100.
175 ≤ hp ≤ 750	2011–2013	2.8.

TABLE III.A–4.—LIMITED-USE NO_X FEL CAPS UNDER THE ALTERNATIVE NO_X STANDARDS—Continued

Power category	Model years	NO_X FEL cap (g/bhp-hr)
(130 ≤ kW ≤ 560)		

For reasons explained in section II.A.1.b.i above, we are also adopting unique phase-in requirements for NO_X standards for engines between 75 and 175 horsepower in order to ensure appropriate lead time for these engines. Because of these unique phase-in provisions, as proposed, we are adopting slightly different provisions regarding 75 to 175 horsepower engines' use of previous-tier credits. Under today's action, manufacturers that choose to demonstrate compliance with these phase-in requirements (*i.e.*, 50 percent in 2012 and 2013 and 100 percent in 2014) or the 1.7 g/bhp-hr alternative NO_X standard (which is based on the 50 percent phase-in option) will be allowed to use Tier 2 NMHC+NO_X credits generated by engines between 50 and 750 horsepower (even though they are not generated by previous-tier engines), along with any other allowable credits, to demonstrate compliance with the Tier 4 NO_X standards for engines between 75 and 175 horsepower during model years 2012, 2013 and 2014 (the years of the phase-in) only. These Tier 2 credits will be subject to the power rating conversion already established in our ABT program, and to the 20% credit adjustment being adopted today for use of NMHC+NO_X credits as NO_X credits.

The requirements for manufacturers that choose to demonstrate compliance with the optional reduced phase-in requirement for engines between 75 and 175 horsepower (i.e, the 25/25/25 percent phase-in option; see Table II.A.–2, note b) or the 2.5 g/bhp-hr alternative NO_X standard (which is based on the 25 percent phase-in option) are different. Under the reduced phase-in requirement, use of credits will be allowed in accordance with the general ABT program provisions. In other words, manufacturers will not have the special allowance to use Tier 2 NMHC+NO_X credits generated by engines between 50 and 750 horsepower noted above to demonstrate compliance with the Tier 4 standards. In addition, manufacturers choosing the reduced phase-in option will not be allowed to generate NO_X credits from engines in this power category in 2012, 2013, and most of 2014, except for use in averaging within this power category (*i.e.*, no banking or trading, or averaging with engines in other power categories will be permitted). This restriction will apply throughout this period even if the reduced phase-in option is exercised during only a portion of this period. We believe that this restriction is important to avoid potential abuse of the added flexibility allowance, considering that larger engine categories will be required to demonstrate substantially greater compliance levels with the 0.30 g/bhp-hr NO_X standard several years earlier than engines built under the reduced phase-in option.

As described in section II.A.3.a of today's action, and as proposed, we are adopting an optional PM standard for air-cooled, hand-startable, direct injection engines under 11 horsepower effective in 2010. In order to avoid potential abuse of this standard, engines certified under this requirement will not be allowed to generate any credits as part of the ABT program. Credit use by these engines will be allowed. The restriction on generating credits should not be a burden to manufacturers, as it will apply only to those air-cooled, hand-startable, direct injection engines under 11 horsepower that are certified under the optional approach, and the production of credit-generating engines would be contrary to the standard's purpose. No adverse comments were submitted to EPA on this issue.

The current ABT program contains a restriction on trading credits generated from indirect injection engines greater than 25 horsepower. The restriction was originally adopted because of concerns over the ability of manufacturers to generate significant credits from existing technology engines (63 FR 56977, October 23, 1998). With today's action, there will be no restriction prohibiting manufacturers from trading credits generated on Tier 4 indirect fuel injection engines greater than 25 horsepower. Based on the certification levels of indirect injection engines, we do not believe there is the potential for manufacturers to generate significant credits from their currently certified engines against the Tier 4 standards. Therefore, as proposed, we are not adopting any restrictions on the trading of credits generated on Tier 4 indirect injection engines to other manufacturers. The restriction placed on the trading of credits generated from Tier 2 and Tier 3 indirect injection engines will continue to apply in the Tier 4 timeframe. No adverse comments were submitted to EPA on this issue.

As explained in the proposal, we are not applying a specific discount to Tier 3 PM credits used to demonstrate compliance with the Tier 4 standards (68 FR 28471, May 23, 2003). PM credits generated under the Tier 3 standards are based on testing performed over a steady-state test cycle. Under the Tier 4 standards, the test cycle is being supplemented with a transient test (see section III.F.1 below). Because in-use PM emissions from Tier 3 engines will vary depending on the type of application in which the engine is used (most applications having higher in-use PM emissions, some having lower in-use PM emissions), the relative "value" of the Tier 3 PM credits in the Tier 4 timeframe will differ. Instead of requiring manufacturers to gather information to estimate the level of in-use PM emissions compared to the PM level of the steady-state test, we believe allowing manufacturers to bring Tier 3 PM credits directly into the Tier 4 time frame without any adjustment is appropriate because it discounts their value for use in the Tier 4 timeframe (since the initial baseline being reduced is higher than measured in the Tier 2 test procedure for most applications). No adverse comments were submitted to EPA on this issue.

3. Are We Expanding the Nonroad ABT Program To Include Credits From Retrofit of Nonroad Engines?

In the proposal, we requested comment on expanding the scope of the standards by setting voluntary new engine emission standards applicable to the retrofit of nonroad diesel engines (68 FR 28471, May 23, 2003). As described in the proposal, retrofit nonroad engines would be able to generate PM and NO_X credits which would be available for use by new nonroad engines in the certification ABT program. We received a significant number of comments on a retrofit ABT program. A number of commenters associated with the agricultural sector were concerned retrofits would be mandatory. Some commenters were opposed to a retrofit credit program that would allow use of the credits under the certification ABT program. However, a number of commenters supported the concept of a retrofit program, but noted a number of concerns regarding the details of such a program, including making sure that any credits earned would be verifiable and enforceable. Some commenters suggested that EPA consider the establishment of a retrofit credit program through a separate rulemaking because there were many details of the program that needed to be explored more fully before adopting such a program. In response to the comments, we are not adopting a retrofit credit program with today's action. Although we provided a detailed explanation of a potential program at proposal,[62] we believe it is important to more fully consider the details of a nonroad engine retrofit credit program and work with interested parties in determining whether a viable program can be developed. EPA intends to explore the possibility of a voluntary, opt-in nonroad retrofit credit program through a separate action later this year. Such a program would be based on the generation of credits beyond the scope of any existing retrofit program. The final rule contains no requirements for retrofitting existing engines or equipment.

B. Transition Provisions for Equipment Manufacturers

1. Why Are We Adopting Transition Provisions for Equipment Manufacturers?

As EPA developed the 1998 Tier 2/3 standards for nonroad diesel engines, we determined, as an aspect of determining an appropriate lead time for application of the requisite technology (pursuant to section 213(b) of the Act), that provisions were needed to avoid unnecessary hardship and to create additional flexibility for equipment manufacturers. The specific concern is the amount of work required and the resulting time needed for equipment manufacturers to incorporate all of the necessary equipment redesigns into their applications in order to accommodate engines that meet the new emission standards. We therefore adopted a set of provisions for equipment manufacturers to provide them with reasonable lead time for the transition process to the newly adopted standards. The program consisted of four major elements: (1) A percent-of-production allowance, (2) a small-volume allowance, (3) availability of hardship relief, and (4) continuance of the allowance to use up existing inventories of engines (63 FR 56977–56978, October 23, 1998 and 68 FR 28472–28476, May 23, 2003).

Given the levels of the newly adopted Tier 4 standards, we believe that there will be engine design and other changes at least comparable in magnitude to those involved during the transition to Tier 2/3. Therefore, with a few exceptions described in more detail below, we are adopting transition provisions for Tier 4 that are similar to those adopted with the previous Tier 2/3 rulemaking. We also note that opportunities for greater flexibility arises from the structure of the Tier 4 rule. For example, Tier 4 consolidates the nine power categories in Tier 2/3 into five categories, providing opportunities for more flexibility by allowing more engine families within each power category, with consequent increased averaging possibilities. The NO_X phase-in also provides increased flexibility opportunities, as do the longer Tier 4 lead times.

We are adding new notification, reporting, and labeling requirements to the Tier 4 program. We believe these additional provisions are necessary for EPA to gain a better understanding of the extent to which these provisions will be used and to ensure compliance with the Tier 4 transition provisions. We are also adopting new provisions dealing specifically with foreign equipment manufacturers and the special concerns raised by the use of the transition provisions for equipment imported into the U.S. The following section describes the Tier 4 transition provisions available to equipment manufacturers. (Section III.C of this preamble describes all of the provisions that will be available specifically for small businesses.)

As under the existing Tier 2/Tier 3 provisions, equipment manufacturers are not obligated to use any of these provisions, but all equipment manufacturers are eligible to do so. Also, as under the existing program, all entities under the control of a common entity, and that meet the regulatory definition of a nonroad vehicle or nonroad equipment manufacturer, must be considered together for the purpose of applying exemption allowances. This will not only provide certain benefits for the purpose of pooling exemptions, but will also preclude the abuse of the small-volume allowances that would exist if companies could treat each operating unit as a separate equipment manufacturer.

2. What Transition Provisions Are We Adopting for Equipment Manufacturers?

The following section describes the transition provisions being adopted with today's action. Areas in which we have made changes to the proposed transition program are highlighted. A complete summary of comments received on the proposed transition program and our response to those comments are contained in the Summary and Analysis of Comments document for this rule.

EPA believes that the lead time provided through the equipment maker transition flexibilities, as adopted in this rule, will be sufficient, as has proved the case in past tiers. These flexibilities provide equipment manufacturers with the selective ability to delay use of the Tier 4 engines in those applications where additional time is needed to successfully incorporate the redesigned engines into their equipment.

Ingersoll-Rand, an equipment manufacturer, submitted a number of comments arguing that significant expansions of the proposed flexibility program are needed if equipment manufacturers are to produce compliant applications within the effective dates of the standards. One suggestion was for EPA to include provisions that provide a definitive period of lead time for incorporation of Tier 4 engines into nonroad equipment. Ingersoll-Rand would have the rules specify a "made available" date before which each engine supplier must provide technical and performance specifications, complete drawings, and a final compliant engine to EPA and the open market. After the mandated "made available" date, equipment manufacturers should be provided a minimum 18 months of lead time to incorporate the new engines into nonroad equipment. One form of the suggestion also entailed a prohibition on design changes once the engine, specifications, drawings, etc. had been initially provided to EPA and to the open market. As an alternative, Ingersoll-Rand urged that the percent of production allowance flexibility be expanded to 150 percent for the power categories between 75 and 750 horsepower and 120 percent for the power category between 25 and 75 horsepower. Ingersoll-Rand believes these levels correspond proportionately to the increased challenges facing equipment manufacturers during Tier 4 as opposed to Tier 2 and Tier 3.

As discussed in greater detail in the Summary and Analysis of Comments, as well as in later parts of this section of this preamble and elsewhere in the administrative record, we disagree with most of Ingersoll-Rand's suggestions. Our fundamental disagreement is with Ingersoll-Rand's premise that Tier 4 will create a situation where need for

[62] *See* memorandum referenced at 68 FR 28471 (May 23, 2003), footnote 299.

expanded equipment maker lead time is the norm rather than the exception so that the rule must provide a drastic, across-the-board expansion of equipment manufacturer lead time. We believe that the lead time provided for equipment makers in this rule is adequate, and that the equipment maker flexibilities we are adopting provide a reasonable and targeted safety valve to deal with isolated problems. There is no across-the-board problem necessitating a drastic expansion of equipment manufacturer lead time, or a drastic expansion of equipment manufacturer flexibilities. We base these conclusions largely on three factors: (a) Our investigation and understanding of the engineering process by which engine makers and equipment manufacturers bring new products to market; (b) the specific engineering challenges which equipment manufacturers will address in complying with the Tier 4 rule; and (c) past practice of equipment manufacturers under previous rules providing transition flexibilities for nonroad equipment.

Because it is in both parties' interest for new engines and new equipment applications to reach the market expeditiously, engine makers and equipment manufacturers usually adopt concurrent engineering programs whereby the new equipment design process occurs simultaneous to the new engine development process. We believe that this concurrent process should work well for Tier 4 because, in many important ways, the engineering challenges facing equipment manufacturers can be anticipated and dealt with early in the design process. We expect that relatively early in the design process, engine manufacturers will be able to define the size and characteristics of the emission control technologies (e.g., NO_X adsorbers and CDPFs), based on the same systems that will be in production for on-highway engines. The equipment manufacturers will concurrently redesign their equipment to accommodate these new technologies, including designing, mounting and supporting the catalytic equipment similar to current exhaust muffler systems.

Moreover, while we expect the redesign challenge for Tier 4 equipment to be similar to that for Tier 2/3, we also expect the redesign to be better and more clearly defined well in advance of the Tier 4 introduction dates. This is because we do not expect the catalyst system size or shape to change significantly during the last 24 months of the engine design and validation process.[63]

We also have studied the extent to which equipment manufacturers have used their flexibilities under the Tier 2/3 program. Although at an early stage in the Tier 2/3 process, initial indications are that the flexibility program is being used by many equipment manufacturers, but in general, manufacturers do not appear to be using the full level of allowances.[64] It appears that the flexibilities are being used as EPA intended, providing manufacturers with flexibility to deal with specific limited situations, rather than to deal with an across-the-board problem.

The emerging pattern is thus the one on which the flexibility program is predicated: there is not a need for across-the-board drastic expansion of equipment manufacturer lead time. Indeed, such an expansion would be inconsistent with the lead time-forcing nature of section 213 (b) of the Act. This is not to say that there is no need for equipment manufacturer flexibilities, or that the Tier 2/3 flexibility format need not be adjusted to accommodate potential problems to be faced under the Tier 4 regime. Instances where additional lead time could be justified are where resource constraints prevent completion of certain applications, or where for business reasons it makes sense for equipment manufacturers to delay completion of small volume families in order to complete larger volume equipment applications. In addition, the Tier 2/3 experience illustrates that there can be instances where emission control optimization which necessitates equipment design changes occurs late in the design cycle, resulting in a need for additional equipment manufacturer lead time. The equipment manufacturer flexibilities adopted in today's rule accommodate these possibilities.

We have specific objections to Ingersoll-Rand's preferred approach of a mandated made available date, followed by 18 months of additional lead time for equipment manufacturers. Superimposing a government mandate on the engine maker—equipment manufacturer business relationship insinuates EPA into the middle of contractual/market relationships (e.g., when is an objectively reasonable delivery date?), forcing EPA to prejudge myriad differing business relationships/engineering situations. Moreover, selection of any single made available date is bound to be arbitrary in most situations. We also believe that the 18-month lead time following a made available date entails a mandated 18-month period (at least) with no return on investment to engine suppliers (i.e. the period between when the Tier 4 engine would be produced and when it could lawfully be sold), which would increase the engine cost, and discourage design changes (since such changes would entail more investment with delayed return on that investment). The ultimate result would be a costlier rule and less environmental benefit due to the delay in introducing Tier 4 engines. Even were EPA to put forth such a regulation, it is not clear that it could be enforced or that it would help the situation. It would only be natural for engine manufacturers to continue to improve its products even after the predefined "made available date" and equipment manufacturers would want to use this improved product even if it meant they had to make last minute changes to the equipment design. For EPA to preclude engine manufacturers from changing their product designs over the period between the certification date and the equipment manufacturer date would be both unusual and counterproductive to our goal of seeing the best possible products available in the market. Moreover, EPA sees no need to interfere with the concurrent design market mechanism, which allows engine makers and equipment manufacturers to negotiate optimal solutions. We believe it is better to leave to the market participants the actual decision for how and when to conduct concurrent engineering designs.

The California Air Resources Board commented that EPA should eliminate or reduce the amount of flexibilities provided for less than 25 horsepower engines, because the Tier 4 engine standards are not aftertreatment-based. The Engine Manufacturers Association commented that we should expand the amount of flexibilities for engines greater than 750 horsepower, given the difficulty of complying with the proposed standards for engines above 750 horsepower. With today's action, we are applying the same flexibility for all power categories, including engines below 25 horsepower and engines above 750 horsepower. While it is true that the Tier 4 standards for engines below 25 horsepower are not aftertreatment-based, we believe there will be changes in engine design for many of those engines in response to the Tier 4 standards. As engine designs change, there is the potential for impacts on

[63] "Tier 4 Nonroad Diesel Equipment Flexibility Provisions," memorandum from Byron Bunker, et al., (EPA) to EPA Air Docket OAR–2003–0012.

[64] "Tier 4 Nonroad Diesel Equipment Flexibility Provisions," memorandum from Byron Bunker, et al., (EPA) to EPA Air Docket OAR–2003–0012.

equipment design as well (as shown in implementing the Tier 2/3 rule). Therefore, we believe providing equipment manufacturer flexibility for engines below 25 horsepower is appropriate and we are adopting the same flexibilities for engines below 25 horsepower as for other power categories. With regard to engines above 750 horsepower, we are retaining the same flexibilities for those engines as for other power categories. As described in section II.A.4, the Tier 4 standards being adopted today for engines above 750 horsepower have been revised from the proposal. We believe that these revisions have appropriately accommodated concerns for the most difficult to design applications (i.e., NO_X adsorbers for engines in mobile applications), so that additional equipment flexibilities are not warranted for these engines.

The Engine Manufacturers Association commented that some equipment manufacturers may be capable of making an on-time transition to the interim Tier 4 standards (e.g. the 2011 standards applicable for 175–750 horsepower engines) without the use of flexibilities. Such equipment manufacturers would like the ability to start the seven-year period in which they may use flexibilities in the year the final Tier 4 standards (the aftertreatment-based standards for both PM and NO_X) take effect. Put another way, they would not need more lead time for equipment to meet the interim standards, but could need more lead time for equipment required to meet the final standards. In addition, the commenter suggested a modified approach that could lead to earlier emission reductions than under the proposed rule: Requiring delayed flexibility engines to meet the interim Tier 4 standards instead of meeting the Tier 2/3 standards (as would have been allowed under the proposal if the flexibilities started in the first year of the interim Tier 4 standards).

EPA wants to encourage the implementation of the Tier 4 standards as early as possible. Therefore, we believe it makes sense to provide incentives to equipment manufacturers to use interim Tier 4 compliant engines in their equipment during the transition to the final Tier 4 standards. Moreover, it is reasonable to expect that more lead time will be needed for the aftertreatment-based standards than for the interim standards. Therefore, in response to these comments, we are revising the proposed flexibility provisions to allow equipment manufacturers to have the option of starting the seven-year period in which flexibility engines may be used in either the first year of the interim Tier 4 standards or the first year of the final Tier 4 standards. For engines between 25 and 75 horsepower, the final Tier 4 standards may begin in 2012 or 2013 depending on whether the manufacturer chooses to comply with the interim 2008 Tier 4 standards. An equipment manufacturer who does not use flexibilities in 2008 thus may need flexibilities as early as 2012. Therefore, the seven-year period for the final Tier 4 standards for engines between 25 and 75 horsepower will begin in 2012 instead of 2013. Moreover, it is clearly appropriate that these delayed flexibility engines meet the interim Tier 4 standards, in order not to backslide from existing levels of performance.

Table III.B–1 shows the years in which manufacturers could choose to start the Tier 4 flexibilities given the standards being adopted today. (The seven-year period for engines below 25 horsepower takes effect in 2008 as proposed, because there are no interim standards for such engines.)

TABLE III.B–1.—FLEXIBILITY PERIODS FOR THE TIER 4 STANDARDS

Power category	Model year flexibility period options	Standards to which flexibility engines would have to certify
25 ≤ hp < 75	2008–2014	Tier 2 standards.
(19 ≤ kW < 56)	2012–2018	Model Year 2008 Tier 4 standards.
75 ≤ hp < 175	2012–2018	Tier 3 standards.
(56 ≤ kW <130)	2014–2020	Model Year 2012 Tier 4 standards.
175 ≤ hp ≤ 750	2011–2017	Tier 3 standards.
(130 ≤ kW ≤ 560)	2014–2020	Model Year 2011 Tier 4 standards.
>750 hp	2011–2017	Tier 2 standards.
(>560 kW)	2015–2021	Model Year 2011 Tier 4 standards.

Under today's action, and as proposed, only those nonroad equipment manufacturers that install engines and have primary responsibility for designing and manufacturing equipment will qualify for the allowances or other relief provided under the Tier 4 transition provisions. As a result of this definition, importers that have little involvement in the manufacturing and assembling of the equipment will be ineligible to receive any allowances. The Engine Manufacturers Association and one engine manufacturer commented that the proposed definition of equipment manufacturer needed to be revised to cover situations in which a manufacturer contracts out the design and production of equipment to another manufacturer. While we understand there are many different types of relationships between equipment manufacturers, we believe it is important to establish firm criteria for determining eligibility to use the equipment manufacturer allowances. We are concerned that the change to the equipment manufacturer definition suggested by the commenters would allow entities that have little or no involvement in the actual design, manufacture and assembly of equipment (*e.g.*, companies that only import equipment) to claim they contracted with an equipment manufacturer to produce equipment for them and therefore claim allowances. This is the exact situation we are attempting to prevent with the changes to the eligibility requirements for the allowances. Therefore, we are adopting the proposed requirement that only those nonroad equipment manufacturers that install engines and have primary responsibility for designing, and manufacturing equipment will qualify for the allowances or other relief provided under the Tier 4 transition provisions. However, we are revising the provisions regarding which engines an equipment manufacturer may include in its total count of U.S.-directed equipment production, which in turn affects the number of allowances an equipment manufacturer may claim. Under today's action, an equipment manufacturer may include equipment produced by other manufacturers under license to them for which they had primary design responsibility (see section 1039.625(a) of the regulations). This should cover the type of situation described by the commenters while preventing an import-only entity from claiming it is an equipment manufacturer and thereby gaining access to the allowances.

a. Percent-of-Production Allowance

Under the percent-of-production allowance adopted today, each equipment manufacturer will be allowed to install engines not certified to the Tier 4 emission standards in a limited percentage of machines produced for the U.S. market. Equipment manufacturers will need to provide written assurance to the engine manufacturer that such engines are being procured for the purpose of the transition provisions for equipment manufacturers. These engines will instead have to be certified to the standards that would apply in the absence of the Tier 4 standards (see Table III.B–1 for the applicable standards). As proposed, this percentage will apply separately to each of the Tier 4 power categories (engines below 25 horsepower, engines between 25 and 75 horsepower, engines between 75 and 175 horsepower, engines between 175 and 750 horsepower, and engines above 750 horsepower) and is expressed as a cumulative percentage of 80 percent over the seven years beginning when the Tier 4 standards apply in a category (see Table III.B–1 for the applicable seven-year periods). No exemptions will be allowed after the seventh year. For example, an equipment manufacturer could install engines certified to the Tier 3 standards in 40 percent of its entire 2011 production of nonroad equipment that use engines rated between 175 and 750 horsepower, 30 percent of its entire 2012 production in this horsepower category, and 10 percent of its entire 2013 production in this horsepower category. (During the transitional period for the Tier 4 standards, the fifty percent of engines that are allowed to certify to the previous tier NO_X standard but meet the Tier 4 PM standard are considered Tier 4-compliant engines for the purpose of the equipment manufacturer transition provisions.) If the same manufacturer produces equipment using engines rated above 750 horsepower, a separate cumulative percentage allowance of 80 percent will apply to those machines during the seven years beginning in 2011 or 2015. This percent-of-production allowance is almost identical to the percent-of-production allowance adopted in the October 1998 final rule (63 FR 56967, October 23, 2003), the difference being, as explained earlier, that there are fewer power categories (and consequent increased flexibility in spreading the flexibility among engine families) associated with the Tier 4 standards.

The 80 percent exemption allowance, were it to be used to its maximum extent by all equipment manufacturers, will bring about the introduction of cleaner engines several months later than would have occurred if the new standards were to be implemented on their effective dates. However, the equipment manufacturer flexibility program has been integrated with the standard-setting process from the initial development of this rule, and as such we believe it is a key factor in assuring that there is sufficient lead time to initiate the Tier 4 standards according to the final implementation schedule.[65]

As proposed, machines that use engines built before the effective date of the Tier 4 standards do not have to be included in an equipment manufacturer's percent of production calculations under this allowance. Machines that use engines certified to the previous tier of standards under our Small Business provisions (as described in section III.C of this preamble) do not have to be included in an equipment manufacturer's percent of production calculations under this allowance. All engines certified to the Tier 4 standards, including those engines that produce emissions at higher levels than the standards, but for which an engine manufacturer uses ABT credits to demonstrate compliance, will count as Tier 4 complying engines and do not have to be included in an equipment manufacturer's percent of production calculations. Engines that meet the Tier 4 PM standards but are allowed to meet the Tier 3 $NMHC+NO_X$ standards during the phase-in period also count as Tier 4 complying engines and do not have to be included in an equipment manufacturer's percent of production calculations.

The choice of a cumulative percent allowance of 80 percent is based on our best estimate of the degree of reasonable lead time needed by equipment manufacturers. We believe the 80 percent allowance responds to the need for flexibility identified by equipment manufacturers, while ensuring a significant level of emission reductions in the early years of the program. (As noted in the following section III.B.2.b, we are adopting a technical hardship provision that allows an equipment manufacturer to request additional relief under the percent of production allowance under certain conditions and with EPA approval.)

b. Technical Hardship Flexibility

Ingersoll-Rand commented that the 80% percent of production allowance level is not sufficient for Tier 4 given the stringency of the standard and the difficulty engine manufacturers will have complying with the standards. In further discussions with Ingersoll-Rand on this issue, they suggested that a percent of production allowance level of 150% for totally non-integrated equipment manufacturers (*i.e.*, equipment manufacturers producing no diesel engines) was appropriate for Tier 4 power categories above 25 horsepower. A fully integrated manufacturer would still receive the 80% level and partially-integrated companies would receive somewhere between 80% and 150% depending on the share of self-produced engines in each specific power category. The basis for this comment is their belief that non-integrated manufacturers are at a disadvantage to integrated manufacturers (manufacturers making both the engine and equipment) when it comes to planning for new Tier 4 engine designs.

Although we do not accept the premise that equipment manufacturer lead time must be drastically expanded across-the-board for the Tier 4 program, we do agree, as explained earlier, that there may be situations where additional lead time, in the form of increased equipment manufacturer transition flexibilities, can be justified. Therefore, we have added an additional flexibility (which has no direct analogue in the Tier 2/3 rule) to this rule in order to provide additional needed lead time in appropriate, individualized circumstances based on a showing of extreme technical or engineering hardship. Ingersoll-Rand has agreed, by letter to EPA, that this provision satisfies all of its concerns regarding

[65] As explained at proposal, for emissions modeling purposes, we have assumed that manufacturers take full advantage of the allowances under the existing transition program for equipment manufacturers (adopted in the October 1998 rule; see 63 FR 56967 (October 23, 2003) in establishing the baseline emissions inventory. In modeling the impact of the Tier 4 standards, because the standards will not take effect for many years and it is not possible to accurately forecast use of the transition program for equipment manufacturers, so to assess costs in a conservative manner, we have assumed that all engines will meet the Tier 4 standards in the timeframe required by the standards without use of the Tier 4 transition provisions. As discussed in section VI.C, this is consistent with our cost analysis, which assumes no use of the transition program for equipment manufacturers.

adequacy of lead time for meeting Tier 4 standards.

This additional flexibility would be available for the three Tier 4 power categories between 25 and 750 horsepower. As noted earlier, Ingersoll-Rand did not believe additional flexibility was needed for engines below 25 horsepower. We agree because the Tier 4 standards for engines below 25 horsepower are not based on the use of advanced aftertreatment. We also are not including this new provision for engines above 750 horsepower because nearly all of the equipment manufacturers utilizing engines above 750 horsepower make small volumes of equipment. The small-volume allowance (described in the following section) allows a manufacturer to exempt a specific number of engines over a seven-year period, which in most cases will be greater than the increased percentage potentially available under this new provision.

This new provision, found in new § 1039.625(m), is a case-by-case exemption granted by EPA to an equipment manufacturer. The equipment manufacturer would have the burden of demonstrating existence of extreme technical or engineering hardship conditions that are outside its control. It must also demonstrate that it has exercised reasonable due diligence to avoid the situation. EPA would treat each request for technical hardship separately, with no guarantee that it would grant the exemption. If EPA grants the exemption, the equipment manufacturer could receive up to an additional 70 percent under the percent of production allowance for each of the three power categories noted above (meaning that there is a potential total 150 percent under the percent of production allowance available, the initial 80 percent available without application, and an additional potential increment of up to 70 percent available on a case-by-case basis).

The exemption could only be granted upon written application to EPA setting forth essentially why the normally successful elements of engine maker/equipment manufacturer design cycle have not provided adequate lead time for a particular equipment model. The application would therefore have to address, with documentation: The engineering or technical problems that have proved unsolvable within the lead time provided, the normal design cycle between the engine maker and equipment manufacturer and why that cycle has not worked in this instance, all information (such as written specifications, performance data, prototype engines) the equipment manufacturer has received from the engine supplier, and a comparison of the design process for the equipment model for which the exemption is requested with the design process for other models for which no exemption is needed. The equipment manufacturer also would have to make and describe all efforts to find other compliant engines for the model. EPA will then evaluate and determine whether or not to grant each such request, and what additional increment under the percent of production allowance (above the 80 percent normally allowed) is justified (not to exceed an additional 70 percent as noted above). As part of our evaluation of requests based on technical hardship, we may contact the engine supplier(s) listed by the equipment manufacturer to check on the accuracy of the engine-related information supplied by the equipment manufacturer. This extension of lead time is premised on the existence of extreme technical or engineering problems, in contrast to the economic hardship provision described in section III.B.2.f below, where consideration of economic impact is critical.

EPA would not grant an application for technical hardship exemption unless the equipment manufacturer demonstrates that the full 80 percent allowed under the percent of production allowance is reasonably expected to be used up in the first two years of the seven-year flexibility period. The reason is obvious. If that allowance would not be fully utilized, then no further extension of lead time can be justified. Furthermore, any technical hardship allowance would have to be used up within two years after the Tier 4 percent of production allowances start for any power category. This is because, although we believe that circumstances of extreme technical or engineering hardship may arise, we cannot see that these circumstances could not be solved within the first two years of the transition. Indeed, Ingersoll-Rand itself clearly indicated that this is a temporary burden which exists during initial model transition and indicated that only 18 months (rather than two years) could be needed from receipt of the certified engine.

This flexibility will be available to all equipment manufacturers, but may only be requested for equipment in which the equipment manufacturer is different than the engine manufacturer. We believe that integrated manufacturers who produce both the equipment and the engine used in the piece of equipment could have an advantage in the equipment redesign process (compared to an equipment manufacturer, whether integrated or not, that uses engines from a different manufacturer) that makes additional relief under the percent of production allowance unnecessary. In addition, integrated equipment manufacturers have other programs available to them (that non-integrated manufacturers do not have) such as the engine averaging, banking and trading program, which can provide lead time flexibility during the transition years. Most basically, integrated manufacturers should be able to design concurrently in all circumstances, so that extreme technical or engineering hardships should not arise.

c. Small-Volume Allowance

The percent-of-production approach described above may provide little benefit to businesses focused on a small number of equipment models, and hence there could be situations where there is insufficient lead time for such models. Therefore, with today's action, we are adopting a small-volume allowance that will allow any equipment manufacturer to exceed the percent-of-production allowances described above during the same seven-year period, provided the manufacturer limits the number of exempted engines to 700 total over the seven years, and to 200 in any one year. The limit of 700 exempted engines (and no more than 200 engines per year) applies separately to each of the Tier 4 power categories (engines below 25 horsepower, engines between 25 and 75 horsepower, engines between 75 and 175 horsepower, engines between 175 and 750 horsepower, and engines above 750 horsepower). In addition, manufacturers making use of this provision must limit exempted engines to a single engine family in each Tier 4 power category.

We are also adopting an alternative small-volume allowance, which equipment manufacturers have the option of utilizing. In discussions regarding the current small-volume allowance, some manufacturers expressed the desire to be able to exempt engines from more than one engine family, but still fall under the number of exempted engine limit. For that reason, we solicited comment on a small-volume allowance program that would allow manufacturers to exempt engines in more than one family, but have lower numerical limits. Under this alternative, manufacturers using the small-volume allowance could exempt 525 machines over seven years (with a maximum of 150 in any given year) for each of the three power categories below 175 horsepower, and 350 machines over seven years (with a maximum of 100 in any given year) for the two power categories above 175 horsepower. Concurrent with the revised caps of 525 or 350, depending on power category, manufacturers could exempt engines from more than one engine family under the small-volume allowance program. Based on sales information for small businesses, we estimated that the alternative small-volume allowance program to include lower numbers of eligible engines and allow manufacturers to exempt more than one engine family would keep the total number of engines eligible for the allowance at roughly the same overall level as the 700-unit program.[66] We also requested comment on allowing equipment manufacturers to choose between the two small-volume allowance programs described above (68 FR 28474–28475, May 23, 2003).

Both engine and equipment manufacturers supported dropping the one engine family restriction from the 700 unit small-volume allowance. In addition, they commented that if the one engine family restriction was not dropped from the 700 unit option, they supported the option of allowing equipment manufacturers to choose between the two small-volume allowance options. With today's action, we are revising the proposed small-volume allowance to allow equipment manufacturers to choose between the 700 unit over seven years option, with exempted engines limited to one engine family, or the proposed alternative which would allow equipment manufacturers to exempt fewer engines over seven years (525 or 350 units, depending on the power category), but with no restriction on the number of engine families that could be included in the exempted engine count. Based on our analysis of small businesses noted above, we expect the number of engines that could be exempted under either option is roughly the same. Giving equipment manufacturers the ability to choose between the two options should not significantly impact the number of engines likely to be exempted under the small-volume allowance. We have not chosen to drop the one engine family restriction from the 700-unit small-volume allowance because it would result in a significant increase in the number of engines eligible to be exempted to levels which we believe are not needed to provide adequate lead time for the Tier 4 program.[67]

As with the percent-of-production allowance, machines that use engines built before the effective date of the Tier 4 standards do not have to be included in an equipment manufacturer's count of engines under the small-volume allowance. Similarly, machines that use engines certified to the previous tier of standards under our Small Business provisions (as described in section III.C of today's action) do not have to be included in an equipment manufacturer's count of engines under the small-volume allowance. All engines certified to the Tier 4 standards, including those that produce emissions at higher levels than the standards but for which an engine manufacturer uses ABT credits to demonstrate compliance, will be considered to be Tier 4 complying engines and do not have to be included in an equipment manufacturer's count of engines under the small-volume allowance. Engines that meet the Tier 4 PM standards but are allowed to meet the Tier 3 $NMHC+NO_X$ standards during the phase-in period (*i.e.*, phase-out engines) will also be considered as Tier 4 complying engines and do not have to be included in an equipment manufacturer's count of engines under the small-volume allowance. All engines used under the small-volume allowance must certify to the standards that would be in effect in the absence of the Tier 4 standards (see Table III.B–1 for the applicable standards). As noted earlier, equipment manufacturers will need to provide written assurance to the engine manufacturer when it purchases engines under the transition provisions for equipment manufacturers.

The Engine Manufacturers Association commented that the proposed regulations for the small-volume allowance established a limit on the total number of engines an equipment manufacturer could use that did not meet the Tier 4 standards and should be revised to set a limit based on U.S.-directed production (consistent with the proposed regulatory language for the percent-of-production allowance). EPA agrees that the limit under the small-volume allowance should apply to U.S.-directed production only—as the commenter surmised, this is what EPA intended—and has revised the final regulations for the small-volume allowance accordingly.

We are also finalizing a technical hardship provision for small business equipment manufacturers using 25–50 horsepower engines, as discussed in III.C.2.b.ii.

d. Early Use of Tier 4 Flexibilities in the Tier 2/3 Timeframe

As proposed, we are also adopting provisions that allow equipment manufacturers to start using a limited number of the new Tier 4 percent of production allowances or Tier 4 small-volume allowances once the seven-year period for the existing Tier 2/Tier 3 program expires (and so continue using engines meeting Tier 1 or Tier 2 standards). In this way, a manufacturer can potentially continue exempting the most difficult applications once the seven-year period of the current Tier 2/3 flexibility provisions is finished. (Under the existing transition program for equipment manufacturers, any unused Tier 2/3 allowances expire after the seven-year period.) However, opting to start using Tier 4 allowances once the seven-year period from the current Tier 2/Tier 3 program expires will reduce the number of exemptions available from the Tier 4 standards under either the percent of production allowance or the small-volume allowance.

With today's action, equipment manufacturers may use up to a total of 10 percent of their Tier 4 percent of production allowances or up to 100 of their Tier 4 small-volume allowances prior to the effective date of the Tier 4 standards. (The early use of Tier 4 allowances will be allowed in each Tier 4 power category.) This amount of equipment utilizing the early Tier 4 allowances will be subtracted from either the Tier 4 allowance of 80 percent under the percent of production allowance or the applicable limit under the small-volume allowance for the appropriate power category, resulting in fewer allowances once the Tier 4 standards take effect. For example, if an equipment manufacturer uses the maximum amount of early Tier 4 percent of production allowances of 10 percent, then the manufacturer will have a cumulative total of 70 percent remaining for that power category when the Tier 4 standards take effect (*i.e.*, 80 percent production allowance minus 10 percent).

The California Air Resources Board commented that we should discount the early use of Tier 4 flexibilities to discourage abuse of the provisions, by requiring equipment manufacturers to give up more than one flexibility after Tier 4 begins for every flexibility used prior to Tier 4. California did not specifically recommend what the discount level should be. We are not adopting a discount for early use of the Tier 4 flexibilities. The intent of

[66] "Analysis of Small Volume Equipment Manufacturer Flexibilities," memo from Phil Carlson (EPA) to Docket A–2001–28.

[67] Memorandum, Phil Carlson to Docket A–2001–28, "Analysis of Equipment Manufacturer Flexibilities," April 15, 2003. Docket A–2001–28, document no. II–B–24.

allowing manufacturers to use the Tier 4 flexibilities early was to allow them to carry over the few remaining equipment models that might not have been redesigned at the end of the seven-year Tier 2/Tier 3 flexibility period until Tier 4 begins, and not requiring a possible double redesign in a short period of time. Because we have placed a relatively low cap (10% under the percent of production allowance or 100 units under the small volume allowance) on the amount an equipment manufacturer could use early from Tier 4, we do not believe that manufacturers will be able to abuse the program and therefore should not have to discount the number of Tier 4 flexibilities used early.

We view this provision on early use of Tier 4 allowances as providing reasonable lead time for introducing Tier 4 engines, since it should result in earlier introduction of Tier 4-compliant engines (assuming that the allowances would otherwise be fully utilized) with resulting net environmental benefit (notwithstanding longer utilization of earlier Tier engines, due to the stringency of the Tier 4 standards) and should do so at net reduction in cost by providing cost savings for the engines that have used the Tier 4 allowances early. (This is another reason we see no reason to discount the allowance.)

e. Early Tier 4 Engine Incentive Program for Equipment Manufacturers

Ingersoll-Rand commented that non-integrated equipment manufacturers who incorporate Tier 4 compliant engines into their equipment prior to the applicable date for the Tier 4 standards should be able to earn early compliance credits. These early compliance credits could allow use of the previous-tier engine (above and beyond the base percentage granted under the flexibility program) for up to 18 months after the certification date of the engine. Ingersoll-Rand also commented that such early compliance credits should be able to be traded across power categories with appropriate weightings applied.

We believe a program that provides an incentive for equipment manufacturers to use early Tier 4-compliant engines is worthwhile from both a technology development perspective and an environmental perspective. As we noted at proposal when we proposed a similar incentive program for engine makers, early use of Tier 4 compliant engines will help foster technology development by getting the Tier 4 technologies out in the market early and provide real-world experience to manufacturers and users (68 FR 28482, May 23, 2003). It will also lead to additional emission reductions above and beyond those expected under the existing Tier 2/3 standards in the years prior to Tier 4 taking effect. Moreover, equipment manufacturers (and especially non-integrated equipment manufacturers) are unlikely to buy early Tier 4 engines without some incentive to do so since these engines are likely to be more expensive than Tier 2/3 engines. For these reasons, we are adopting new provisions that will allow any equipment manufacturer to earn early compliance credits that could be used to increase the number of equipment flexibilities above and beyond the levels allowed under the percent of production allowance or small-volume allowance (and for reasons independent of those allowances: namely, an inducement to make early use of Tier 4 engines).

The program will be available to all equipment manufacturers regardless of whether they are integrated or non-integrated. While Ingersoll-Rand commented that the program should be available to non-integrated equipment manufacturers only, we believe the program should provide an incentive for all equipment manufacturers to use early Tier 4 engines (since the benefits accruing from early use of such engines exist regardless of whether the equipment manufacturer is integrated with the engine maker).

Before describing this provision further, it is desirable to put it in context by explaining its relationship to the engine manufacturer incentive program for early Tier 4 or very low emission engines (described in section III.M below), as well as to the similar incentive provisions for engine manufacturers which we proposed (68 FR 28482, May 23, 2003). We are, in essence, redirecting the proposed incentive for using early Tier 4 compliant engines to equipment manufacturers. Thus, under today's rule, an engine manufacturer could use the incentive program (as described in section III.M) only if an equipment manufacturer uses an early Tier 4 engine but (for whatever reason) declines to use the early engine flexibility allowance. In such a case, the engine manufacturer could opt to earn either "engine offsets" (which would allow them to make fewer engines certified to the Tier 4 standards once the Tier 4 program takes effect) or ABT credits, but not both. In the more likely case of an equipment manufacturer using early Tier 4 engines and using the incentive flexibilities itself, the engine manufacturer would be eligible to generate ABT credits from such early Tier 4 compliant engines.

The early Tier 4 engine incentive program for equipment manufacturers will apply to the four power categories above 25 horsepower where the use of advanced exhaust aftertreatment is expected under the Tier 4 standards. Because the Tier 4 standards for engines below 25 horsepower are not expected to result in the use of advanced aftertreatment technologies, we are not including such engines in the program.

In order for an engine to be considered an early Tier 4 compliant engine, it will need to be certified to the final Tier 4 standards for PM, NO_X, and NMHC (*i.e.*, the 2013 standards for engines between 25 and 75 horsepower, the 2014 standards for engines between 75 and 175 horsepower, the 2014 standards for engines between 175 and 750 horsepower, and the 2015 standards for engines above 750 horsepower) or to the final PM and NMHC standards and the alternative NO_X standards during the phase-in (as described in section II.A.2.c of today's rule for engines between 75 and 750 horsepower). In order to be an early Tier 4 compliant engine, these engines would also have to certify to the Tier 4 CO standards. Because 15 ppm sulfur diesel fuel will be available on a widespread basis in time for 2007 (due to the requirements for on-highway heavy-duty engines), we are allowing engine manufacturers to begin certifying engines to the Tier 4 standards, and therefore have engines eligible for the early Tier 4 engine incentive program, beginning with the 2007 model year.

In order to provide assurance that early Tier 4 compliant engines are placed into equipment earlier than would otherwise happen under the Tier 4 program, engine manufacturers will be required to certify and start producing such engines before September 1 of the year prior to the post-2011 Tier 4 standards taking effect or before September 1, 2010 for engines in the 175 to 750 horsepower category. Similarly, equipment manufacturers will be required to install such engines in equipment before January 1 of the year the post-2011 Tier 4 standards take effect or before January 1, 2011 for engines in the 175 to 750 horsepower category. In addition, in order to be considered an early Tier 4 compliant engine, such engines would be required to comply with all of the requirements associated with the final Tier 4 standards such as NTE requirements, transient testing (where otherwise required for certification, *i.e.* for 25–750 horsepower engines), and closed crankcase requirements. Finally, for engines certified prior to model year 2011, the engine manufacturer would be allowed to demonstrate early compliance with the Tier 4 standards on a 15 ppm sulfur fuel (as allowed under the certification fuel requirements specified in section III.D of today's rule) provided the engine manufacturer demonstrates that the equipment in which the engines are placed will use fuel meeting this low sulfur specification and includes appropriate information on the engine label and ensures that ultimate purchasers of equipment using these engines are informed that ultra low-sulfur diesel fuel is recommended (see section 1039.104(e) of the regulations). Equipment manufacturers using such pre-2011 engines in their equipment would likewise need to take steps to ensure that fuel meeting this low sulfur specification is used in the equipment once operated in use to earn the additional flexibility allowances.

Equipment manufacturers installing engines complying with the final Tier 4 standards (as described above) would earn one flexibility allowance for each early Tier 4 compliant engine used in its equipment. Equipment manufacturers installing engines between 75 and 750 horsepower that comply with the final Tier 4 PM standard and the alternative NO_X standard (described in section II.A.2.c) would earn one-half of a flexibility allowance for each early Tier 4 compliant engine used in its equipment. Table III.B–2 presents the requirements an engine would need to meet to be considered an early Tier 4 engine for the purposes of this early Tier 4 engine incentive program.

TABLE III.B–2.—REQUIREMENTS FOR ENGINES
[Under the Early Tier 4 Engine Incentive Program]

Power category	Tier 4 standards the engines must meet	Date before which engines must be installed by the equipment manufacturer	Number of flexibility allowances earned for use of early tier 4 engines
25 ≤ hp < 75 (19 ≤ kW < 56)	Model Year 2013	January 1, 2013[a]	1–to–1
75 ≤ hp < 175	Model Year 2014	January 1, 2012	1–to–1
(56 ≤ kW <130)	Model Year 2012[b]	January 1, 2012	0.5–to–1
175 ≤ hp ≤ 750	Model Year 2014	January 1, 2011	1–to–1
(130 ≤ kW ≤ 560)	Model Year 2011[b]	January 1, 2011	0.5–to–1
Generator Sets >750 hp (>560 kW)	Model Year 2015	January 1, 2015	1–to–1
Other Machines >750 hp (>560 kW)	Model Year 2015	January 1, 2015	1–to–1

[a] The installation date for 50 to 75 horsepower engines purchased from manufacturers choosing to opt out of the 2008 model year Tier 4 standards and instead comply with the Tier 4 standards beginning in 2012 would be January 1, 2012.

[b] To be eligible, engines must meet the 0.01g/bhp-hr PM standard and the alternative NO_X standards in section 1039.102 (e) described in section II.A.2.c.

As described above, equipment manufacturers using early Tier 4 compliant engines can earn flexibility allowances that can be used to effectively increase the number of allowances provided under the percent of production allowance or the small volume allowance in the same power category. For example, an equipment manufacturer that uses 500 engines in the 175 to 750 horsepower category that met the model year 2011 PM standards and alternative NO_X standards would earn 250 additional flexibility allowances in that power category. That manufacturer could then exclude 250 engines from its calculations before demonstrating compliance with the 80 percent limit under the percent of production allowance (or the applicable limit under the small volume allowance if the equipment manufacturer is using that option) once Tier 4 starts in that power category.

Equipment manufacturers would be required to report certain information regarding the early Tier 4 compliant engines (such as engine family name, number of engines used prior to Tier 4 in each power category, the rated power of the engines, and the type of application the engines above 750 horsepower were used in) when they submit their first report under the Tier 4 flexibility program. For engines above 750 horsepower, equipment manufacturers also would be required to keep records of how many early Tier 4 compliant engines are used in generator sets, versus how many are used in other machinery. This is because the additional flexibility allowances earned from the use of early Tier 4 compliant engines used in generator sets could only be used for additional flexibility allowances for generator sets. Likewise, the additional flexibility allowances earned from the use of early Tier 4 compliant engines used in mobile machinery (labeled 'other machinery' in the table above) applications could only be used for additional flexibility allowances for other non-generator set applications.

Under the early Tier 4 engine incentive program, we will allow equipment manufacturers to "trade" the additional flexibilities earned in the two power categories between 75 and 750 horsepower, with the power rating of the engines factored into the "trade" to ensure equivalent emissions for the engines generating the early allowances and the engines using the allowances. For example, an equipment manufacturer that earned 100 additional flexibility allowances under the early Tier 4 engine incentive program from 100 horsepower engines, could "trade" those flexibilities into the next power category up (175 to 750 horsepower). The equipment manufacturer would generate 10,000 horsepower-allowances from those early engines (*i.e.*, 100 horsepower times 100 allowances). The equipment manufacturer could then produce, for this example, an additional 25 engines with a power rating of 400 horsepower above and beyond the normal limit on allowances (or any other combination of engines such that the sum of the horsepower-weighted allowances adds up to the 10,000 horsepower-allowances used in this example). We are not allowing trading for engines in the 25 to 75 horsepower category because the Tier 4 standards for these engines are based on the application of only PM aftertreatment technology. Similarly, we are not allowing trading for engines in the above 750 horsepower category because the Tier 4 standards are based on the application of PM aftertreatment to all engines, but NO_X aftertreatment for only some engines.

f. Economic Hardship Relief Provision

With today's action, and as proposed, we are providing an additional Tier 4 transition flexibility for "economic hardship relief" for equipment manufacturers. Under the economic hardship relief provisions, an equipment manufacturer that does not make its own engines could obtain limited additional relief by providing evidence that, despite its best efforts, it cannot meet the implementation dates, even with the Tier 4 equipment flexibility program provisions outlined above. Such a situation could occur if an engine supplier without a major business interest in the equipment manufacturer were to change or drop an engine model very late in the implementation process. The purpose of the provision is to redress individual situations of extreme economic hardship, not merely to perpetuate existing market share. That is, if situations arise where one equipment maker cannot produce equipment using Tier 4-compliant engines by the compliance date, but another can, ordinarily EPA would not adjust the program to allow use of the non-compliant application absent extreme, compelling equitability considerations.

Applications for economic hardship relief will have to be made in writing, and will need to be submitted before the earliest date of noncompliance. The application will also have to include evidence that failure to comply is not the fault of the equipment manufacturer (such as a supply contract broken by the engine supplier), and include evidence that serious economic hardship to the company will result if relief is not granted. (As explained in section III.B.2.b above, this is a significant difference between this economic hardship provision and the technical hardship flexibility, where consideration of cost is generally irrelevant.) We expect to work with the applicant to ensure that all other remedies available under the flexibility provisions are exhausted before granting additional relief (if appropriate), and place a limit on the period of relief to no more than one year. Applications for economic hardship relief generally will only be accepted during the first year after the effective date of an applicable new emission standard.

The Agency expects this provision will be rarely used. This expectation has been supported by our initial experience with the Tier 2 standards in which only one equipment manufacturer has applied under the existing hardship relief provisions (and the request was subsequently denied). Requests for economic hardship relief will be evaluated by EPA on a case-by-case basis, and may require, as a condition of granting the applications, that the equipment manufacturer agree (in writing) to some appropriate measure to recover the lost environmental benefit.

Ingersoll-Rand commented that the provisions regarding eligibility for hardship relief should be revised so that they do not require a demonstration of severe economic hardship, noting that such a showing would invariably preclude large entities (like Ingersoll-Rand) from utilizing the provision, even though delays were beyond their control. As described earlier in this section, we have included an additional flexibility in the Tier 4 rule in order to provide additional needed lead time in appropriate, individualized circumstances based on a showing of extreme technical or engineering hardship. We believe the provisions of the technical hardship address the concerns noted by Ingersoll-Rand in their comments, and therefore we are not revising the existing economic hardship relief provisions (which require a demonstration of severe economic impact) for the Tier 4 final program.

g. Existing Inventory Allowance

The current program for nonroad diesel engines includes a provision for equipment manufacturers to continue to use engines built prior to the effective date of new standards, until the older engine inventories are depleted. It also prohibits stockpiling of previous tier engines. As proposed, we are extending these provisions for the transition to the Tier 4 standards adopted today. We are also extending the existing provision that provides an exception to the applicable compliance regulations for the sale of replacement engines. In extending this provision, we are requiring that engines built to replace certified engines be identical in all material respects to an engine of a previously certified configuration that is of the same or later model year as the engine being replaced. The term "identical in all material respects" allows for minor differences that would not reasonably be expected to affect emissions such as a change in materials or a change in the company supplying the components of the engine.

3. What Are the Recordkeeping, Notification, Reporting, and Labeling Requirements Associated With the Equipment Manufacturer Transition Provisions?

The following section describes the recordkeeping, notification, reporting, and labeling requirement being adopted today. As proposed, failure to comply with these requirements will subject the noncomplying party to penalties as described in 40 CFR 1068.101.

a. Recordkeeping Requirements for Engine and Equipment Manufacturers

With today's action, we are extending the recordkeeping requirements from the current equipment manufacturer transition program. Under the Tier 4 transition program, engine manufacturers will be allowed to continue to build and sell previous tier engines needed to meet the market demand created by the equipment manufacturer flexibility program, provided they receive written assurance from the engine purchasers that such engines are being procured for this purpose. Engine manufacturers will be required to keep copies of the written assurance from the engine purchasers for at least five full years after the final year in which allowances are available for each power category.

Equipment manufacturers choosing to take advantage of the Tier 4 allowances will be required to: (1) Keep records of the production of all pieces of equipment excepted under the allowance provisions for at least five full years after the final year in which allowances are available for each power category; (2) include in such records the serial and model numbers and dates of production of equipment and installed engines, and the rated power of each engine, (3) calculate annually the number and percentage of equipment made under these transition provisions to verify compliance that the allowances have not been exceeded in each power category; and (4) make these records available to EPA upon request.

b. Notification Requirements for Equipment Manufacturers

We are adopting new notification requirements for equipment manufacturers with the Tier 4 program. Under the Tier 4 transition program, equipment manufacturers wishing to participate in the Tier 4 transition provisions will be required to notify EPA prior to their use of the Tier 4 transition provisions. Equipment manufacturers will be required to submit their notification before the first calendar year in which they intend to use the transition provisions. We believe that prior notification will greatly enhance our ability to ensure compliance. Under the newly adopted notification requirements, each equipment manufacturer will be required to notify EPA in writing and provide the following information prior to the start of the first year in which the manufacturer intends to use the flexibilities:

(1) The nonroad equipment manufacturer's name, address, and contact person's name, phone number;

(2) The allowance program that the nonroad equipment manufacturer intends to use by power category;

(3) The calendar years in which the nonroad equipment manufacturer intends to use the exception;

(4) An estimation of the number of engines to be exempted under the transition provisions by power category;

(5) The name and address of the engine manufacturer from whom the equipment manufacturer intends to obtain exempted engines; and

(6) Identification of the equipment manufacturer's prior use of Tier 2/3 transition provisions.

Engine manufacturers supported the new notification requirements for equipment manufacturers. One equipment company, however, commented that the notification requirements are of minimal value and should be deleted. We disagree and continue to believe the new notification requirements will greatly enhance our ability to ensure compliance with the flexibility provisions. Given the limited information that must be provided by equipment manufacturers, we do not expect that the notifications will require any significant effort to pull the information together and submit to EPA.

EPA had requested comment on whether the notification provisions should also apply to the current Tier 2/Tier 3 transition program, and if so, how these provisions should be phased in for equipment manufacturers using the current Tier 2/Tier 3 transition provisions. We did not receive any comments on this issue. However, consistent with our approach to several other Tier 4 requirements that we were considering applying to the Tier 2/Tier 3 transition program, we are not adopting such notification requirements for equipment manufacturers for the current Tier 2/Tier 3 program.

c. Reporting Requirements for Engine and Equipment Manufacturers

As with the current program, engine manufacturers who participate in the Tier 4 program will be required to submit information each year on the number of such engines produced and to whom the engines are provided. The purpose of these submittals is to help EPA monitor compliance with the program and prevent abuse of the program.

We are adopting new reporting requirement for equipment manufacturers participating in the Tier 4 equipment manufacturer transition provisions. With today's action, equipment manufacturers participating in the program will be required to submit an annual written report to EPA that calculates its annual number of exempted engines under the transition provisions by power category in the previous year. Equipment manufacturers using the percent of production allowance, will also have to calculate the percent of production the exempted engines represented for the appropriate year. Each report will include a cumulative calculation (both total number and, if appropriate, the percent of production) for all years the equipment manufacturer is using the transition provisions for each of the Tier 4 power categories. In order to ease the reporting burden on equipment manufacturers, EPA intends to work with the manufacturers to develop an electronic means for submitting information to EPA.

EPA had requested comment on whether these new reporting requirements for equipment manufacturers should also apply to the current Tier 2/Tier 3 transition program, and if so, how these provisions should be phased in for equipment manufacturers using the current Tier 2/Tier 3 transition provisions. We did not receive any comments on this issue. However, consistent with our approach to several other Tier 4 requirements that we were considering applying to the Tier 2/Tier 3 transition program, we are not adopting reporting requirements for equipment manufacturers for the current Tier 2/Tier 3 program.

d. Labeling Requirements for Engine and Equipment Manufacturers

Engine manufacturers are currently required to label their certified engines with a label that contains a variety of information. Under today's action, as proposed, we are adopting requirements that engine manufacturers be required to identify on the engine label if the engine is exempted under the Tier 4 transition program. In addition, and also as proposed, equipment manufacturers will be required to apply a label to the engine or piece of equipment that identifies the equipment as using an engine produced under the Tier 4 transition program for equipment manufacturers.

Engine manufacturers were opposed to the new labeling requirements. We believe these new labeling requirements will allow EPA to easily identify the exempted engines and equipment, verify which equipment manufacturers are using these exceptions, and more easily monitor compliance with the transition provisions. Labeling of the equipment should also help U.S. Customs to quickly identify equipment being imported using the exemptions for equipment manufacturers.

4. What Are the Requirements Associated With Use of Transition Provisions for Equipment Produced by Foreign Manufacturers?

Under the current regulations in 40 CFR 89.2, importers are treated as equipment manufacturers and are each allowed the full allowance under the transition provisions in 40 CFR 89.102(d). Therefore, under the current provisions, importers of equipment from a foreign equipment manufacturer could as a group import more excepted equipment from that foreign manufacturer than 80% of that manufacturer's production for the U.S. market (*i.e.*, more than the percent-of-production), or more than the small-volume allowance. Therefore, the current regulation creates a potentially significant adverse environmental impact. EPA did not intend this outcome, and does not believe it is needed to provide reasonable lead time to foreign equipment manufacturers. EPA thus proposed to change the current regulations to eliminate this disparity.

As noted earlier, with today's action, only those nonroad equipment manufacturers that install engines and have primary responsibility for designing and manufacturing equipment will qualify for the allowances or other relief provided under the Tier 4 transition provisions. Foreign equipment manufacturers who comply with the compliance related provisions discussed below will receive the same allowances and other transition provisions as domestic manufacturers. Foreign equipment manufacturers who do not comply with these compliance related provisions will not receive allowances. Importers that have little involvement in the manufacturing and assembling of the equipment will not receive any allowances or other transition relief directly, but can import exempt equipment if it is covered by an allowance or transition provision associated with a foreign equipment manufacturer. These provisions allow the transition allowances and other provisions to be used by foreign equipment manufacturers in the same way as domestic equipment manufacturers, while avoiding the potential for importers using unnecessary allowances.

Under today's action, a foreign equipment manufacturer includes any equipment manufacturer that produces equipment outside of the United States that is eventually sold in the United States. All foreign nonroad equipment manufacturers wishing to use the transition provisions will have to comply with all requirements of the regulation discussed above including: Notification, recordkeeping, reporting and labeling. Along with the equipment manufacturer's notification described earlier, a foreign nonroad equipment manufacturer will have to comply with various compliance related provisions similar to those adopted in several fuel regulations relating to foreign refiners.[68] As part of the notification, the foreign nonroad equipment manufacturer will have to:

(1) Agree to provide EPA with full, complete and immediate access to conduct inspections and audits;

(2) Name an agent in the District of Columbia for service of process;

(3) Agree that any enforcement action related to these provisions will be governed by the Clean Air Act;

(4) Submit to the substantive and procedural laws of the United States;

(5) Agree to additional jurisdictional provisions;

(6) Agree that the foreign nonroad equipment manufacturer will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors for actions performed within the scope of EPA employment related to the provisions of this program;

(7) Agree that the foreign nonroad equipment manufacturer becomes subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity; and

(8) Submit all reports or other documents in the English language, or include an English language translation.

In addition to these requirements, we are adopting a new provision for foreign equipment manufacturers that participate in the transition program to comply with a bond requirement for engines imported into the U.S. We believe the bond requirements are an important tool to ensure that foreign equipment manufacturers are subject to the same level of enforcement as domestic equipment manufacturers. Furthermore, we believe that a bonding requirement for the foreign equipment manufacturer is an important enforcement tool in order to ensure that EPA has the ability to collect any judgements assessed against a foreign equipment manufacturer for violations of these transition provisions.

Under the bond program adopted today, a participating foreign equipment manufacturer will have to obtain annually a bond in the proper amount that is payable to satisfy United States judicial judgments that results from administrative or judicial enforcement actions for conduct in violation of the Clean Air Act. The foreign equipment manufacturer will have two options for complying with the bonding requirement. The foreign equipment manufacturer can:

(1) Obtain a bond in the proper amount from a third-party surety agent that is cited in the U.S. Department of Treasury Circular 570, "Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds and as Acceptable Reinsuring Companies"; or

(2) Obtain an EPA waiver from the bonding requirement, if the foreign equipment manufacturer can show that it has assets of an appropriate value in the United States.

EPA expects the second bond option to address instances where an equipment manufacturer produces equipment outside the United States containing flexibility engines, but also has facilities (and thus significant assets) inside the United States. Under this second option, such a manufacturer can apply to the EPA for a waiver of the bonding requirement.

Because EPA's concerns of compliance will relate to the nature and tier of engines used in the transition equipment, we believe the bond value should be related to the value of the engine used. Therefore, we are adopting requirements that the bond be set at a level designed to represent approximately 10% of the cost of the engine for each piece of transition equipment produced for import into the United States under this program. So that manufacturers have certainty regarding the bond amounts and so that there isn't a need for extensive data submittals and evaluation between EPA and the manufacturer, the rule specifies the bond value for each imported engine based on the estimated average cost for a Tier 4 engine on which the bond would be based. Based on average engine cost estimates from table 6.2–5 of the final RIA, equipment using engines exempted under the transition program will require a bond in the amount shown in table III.B–3.

TABLE III.B–3.—BOND VALUE FOR ENGINES IMPORTED

[Under the Tier 4 Transition Program]

Power range	Per engine bond value (dollars)
$0 < hp < 25$	150
$25 \leq hp < 75$	300
$75 \leq hp < 175$	500
$175 \leq hp < 300$	1,000
$300 \leq hp < 600$	3,000
$hp \geq 600$ hp	8,000

Depending on the number of engines/equipment brought into the U.S. each year, the value of the bond calculated using the above values could change from year to year. Under the provisions adopted today, an importer would calculate the estimated bond amount using the values in table III.B–3 and be required to obtain a bond equal to the highest bond value estimated over the seven-year flexibility period. Because we have the authority to bring enforcement actions against a manufacturer for five years beyond the end of the program, the manufacturer would be required to maintain the bond for five years beyond the end of the flexibility period or five years after using up all of its available allowances, whichever occurs first. Finally, if a foreign equipment manufacturer's bond is used to satisfy a judgment within the seven-year flexibility period, the foreign equipment manufacturer will then be required to increase the bond to cover the amount used within 90 days of the date the bond is used.

Most comments received on this issue supported the proposed provisions. However, Ingersoll-Rand commented that EPA should clarify whether the special requirements for foreign equipment manufacturers apply to U.S.-based companies that have foreign manufacturing facilities. Ingersoll-Rand believes that such requirements should not apply because EPA appears to be concerned about abuse of the program by foreign companies that export machines into the U.S. With today's action, all equipment manufacturers who import equipment into the U.S. will be required to comply with the provisions for foreign equipment manufacturers, even if they are U.S.-based companies. Because there is a wide range of actual presence in this country for "U.S.-based" companies,

[68] See, for example, 40 CFR 80.410 concerning provisions for foreign refiners with individual gasoline sulfur baselines.

EPA believes it is important that all companies importing equipment to the U.S. comply with the requirements for foreign equipment manufacturers. Neither the notification requirements described earlier for foreign equipment manufacturers nor the bonding requirements should cause any burden for companies with significant presence in this country. We would expect that only those companies with limited presence or no presence in this country will be impacted to any measurable degree because of the requirements placed on foreign equipment manufacturers.

In addition to the foreign equipment manufacturer requirements discussed above, EPA is also requiring importers of exempted equipment from a complying foreign equipment manufacturer to comply with certain provisions. EPA believes these importer provisions are essential to EPA's ability to monitor compliance with the transition provisions. Under today's action, each importer will be required to notify EPA prior to their initial importation of equipment exempted under the Tier 4 transition provisions. Importers will be required to submit their notification prior to the first calendar year in which they intend to import exempted equipment from a complying foreign equipment manufacturer under the transition provisions. The importer's notification will need to include the following information:

(1) The name and address of importer (and any parent company);

(2) The name and address of the manufacturers of the exempted equipment and engines the importer expects to import;

(3) Number of exempted equipment the importer expects to import for each year broken down by equipment manufacturer and power category; and

(4) The importer's use of the transition provisions in prior years (number of flexibility engines imported in a particular year, under what power category, and the names of the equipment and engine manufacturers).

In addition, EPA is requiring that any importer electing to import to the United States exempted equipment from a complying foreign equipment manufacturer will have to submit annual reports to EPA. The annual report will have to include the number of exempted equipment the importer actually imported to the United States in the previous calendar year; and the identification of the equipment manufacturers and engine manufacturers whose exempted equipment/engines were imported.

C. Engine and Equipment Small Business Provisions (SBREFA)

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions. As EPA believed that the ultimate rule could have a significant economic impact on small businesses, we prepared a regulatory flexibility analysis as part of this rulemaking. We prepared an Initial Regulatory Flexibility Analysis (IRFA) pursuant to section 603 of the RFA which is part of the record for the NPRM, and we prepared a Final Regulatory Flexibility Analysis (FRFA) to support today's action.

Under section 609(b) of the RFA, a Small Business Advocacy Review Panel (SBAR Panel or Panel) is required to be convened prior to publication of both an IRFA and a FRFA. Section 609(b) of the RFA directs the Panel to, through outreach with small entity representatives (SERs), report on the comments of the SERs and make findings under section 603 of the RFA on issues related to identified elements of an IRFA during the proposal stage of a rulemaking. During the development of the rulemaking, EPA is to analyze the elements of the IRFA in developing the FRFA for the final rulemaking (see section X.C of this preamble for more discussion on the elements of a FRFA). The purpose of the Panel was to gather information to identify impacts on small businesses and to develop potential regulatory options to mitigate these concerns. At the completion of the SBAR Panel process, the Panel prepared a Final Panel Report. This report includes:

- Background information on the proposed rule being developed;
- Information on the types of small entities that would be subject to the proposed rule;
- A description of efforts made to obtain the advice and recommendations of representatives of those small entities; and,
- A summary of the comments that had been received to date from those representatives.

The Panel report was included in the proposal's rulemaking record (and hence in the rulemaking record for this final rule), and provided the Panel and the Agency with an opportunity to identify and explore potential ways of shaping the rule to minimize the burden of the rule on small entities while achieving the rule's purposes and being consistent with Clean Air Act statutory requirements.

EPA approached this process with care and diligence. To identify representatives of small businesses for this process, we used the definitions provided by the Small Business Administration (SBA) for manufacturers of nonroad diesel engines and vehicles. The categories of small entities in the nonroad diesel sector that will potentially be affected by this rulemaking are defined in the following table:

Industry	Defined as small entity by SBA if:	Major SIC codes
Engine manufacturers.	Less than 1,000 employees.	Major Group 35
Equipment manufacturers:		
—construction equipment.	Less than 750 employees.	Major Group 35
—industrial truck manufacturers (*i.e.*, forklifts).	Less than 750 employees.	Major Group 35
—all other nonroad equipment manufacturers.	Less than 500 employees.	Major Group 35

One small engine manufacturer and 5 small equipment manufacturers agreed to serve as Small Entity Representatives (SERs) throughout the SBAR Panel process for this proposal. These companies represented the nonroad market well, as the group of SERs consisted of businesses that manufacture various types of nonroad diesel equipment.

The following are the provisions recommended by the SBAR Panel. As described in section III.B above, there are other provisions that apply to all equipment manufacturers; however, the discussion in this section focuses mainly on small entities.

1. Nonroad Diesel Small Engine Manufacturers

a. Lead Time Transition Provisions for Small Business Engine Manufacturers

i. Panel Recommendations and Our Proposal

The transition provisions recommended by the SBAR Panel for engines produced or imported by small entities are listed below. For all of the provisions, the Panel recommended that small business engine manufacturers and small importers must have certified engines in model year 2002 or earlier in order to take advantage of these provisions. Each manufacturer would be limited to 2,500 units per year as this number allows for some market growth. The Panel recommended these stipulations in order to prohibit the misuse of the transition provisions as a tool to enter the nonroad diesel market or to gain unfair market position relative to other manufacturers.

Currently, certified nonroad diesel engines produced by small manufacturers all have a horsepower rating of 80 or less. At proposal, we considered both a one-step approach, and the two-step approach which we are finalizing today. Due to the structure of the standards and their timing, EPA proposed transition provisions for small business engine manufacturers which encompassed both approaches recommended by the Panel, with the inclusion of the 2,500 unit limit (as suggested by the Panel) for each manufacturer. Given the two-step structure of the final rule, we are only providing those proposed provisions related to that approach (a complete description of the provisions proposed by the Panel, and also by specific Panel members, is located in the SBAR Final Panel Report).

For a two-step approach the Panel recommended that:

• An engine manufacturer should be allowed to skip the first phase and comply on time with the second; or,

• A manufacturer could delay compliance with each phase of standards for up to three years.

We proposed the following provisions in the NPRM (based on available data, we believe that there are no small manufacturers of nonroad diesel engines above the 75–175 hp category):

With regard to PM—

• Engines under 25 hp and those between 75 and 175 hp have only one standard so the manufacturer could delay compliance with these standards for up to three years.

• For engines between 50 and 75 hp, we proposed to delay compliance for one year if the 2008 interim standards are met, with the stipulation that small business manufacturers cannot use PM credits to meet the interim standard. However, if a small manufacturer elects the optional approach to the standard (elects to skip the interim standard), no further relief will be provided.

With regard to NO_X—

• There is no change in the level of the NO_X standard for engines under 25 hp and those between 50 and 75 hp, so we did not propose any special provisions for these categories.

• For engines in the 25–50 hp and the 75–175 hp categories we proposed a three year delay in the program consistent with the one-phase approach recommendation above.

ii. What We Are Finalizing

We are finalizing all of the provisions set out above for NO_X. For PM, we are finalizing some of the proposed provisions with certain revisions, as described below. In finalizing these provisions, we considered not only the recommendations of the Panel, but also the public comments on the proposed small business engine manufacturer transition provisions. Extensions of an applicable standard also apply to all certification requirements associated with that standards (so that transient and NTE testing would not be required until expiration of the extension). Based on available data, and further conversations with manufacturers during the development of this rulemaking (documented in the administrative record), we have found no small business manufacturers of nonroad diesel engines above 175 hp.

For engines under 25 hp:

• PM—a manufacturer may elect to delay compliance with the standard for up to three years.

• NO_X—there is no change in the level of the existing NO_X standard for engines in this category, so no special provisions are being provided.

For engines in the 25–50 hp category:

• PM—manufacturers must comply with the interim standards (the Tier 4 requirements that begin in model year 2008) on time, and may elect to delay compliance with the 2013 Tier 4 requirements (0.02 g/bhp-hr PM standard) for up to three years. Due to an oversight at proposal, we did not include transition provisions for this category in the NPRM, but there is no reason to exclude them when all other small business engines are eligible for extensions. We therefore are adopting a three year extension with today's action. As engines in this category must meet the 2008 standard, we are not conditioning this three year extension on meeting this standard. (Please note the distinction between these engines and engines in the 50–75 hp power band, where we are conditioning a three-year extension on meeting the 2008 standards. The difference is that engines in the 50–75 hp category have an option of whether or not to meet those 2008 standards. We consequently have structured the small business engine extension to encourage a choice to comply with those standards.)

• NO_X—a manufacturer may elect to delay compliance with the standard for up to three years.

For engines in the 50–75 hp category:

• As proposed, EPA is adopting special provisions for these engines, reflecting the special provisions in the rules which give engine manufacturers the choice of meeting an interim standard for PM in 2008 and meeting the aftertreatment-based standard in 2013, or meeting the aftertreatment-based standard in 2012 without meeting an interim standard. A small business engine manufacturer may delay compliance with the 2013 Tier 4 requirement of 0.02 g/bhp-hr PM for up to three years provided that it complies with the interim Tier 4 requirements that begin in model year 2008 on time, without the use of credits. We proposed an extension of only one year, but this would be inconsistent with the extension period we are adopting, and which we proposed, for all of the other power categories. In addition, this provision for 50–75 hp engines is structured to encourage small business engine manufacturers to opt for early PM reductions by meeting the 2008 interim PM standard, so that an extension of three years is appropriate as an incentive. We are requiring that these engines achieve the 2008 standard without use of credits to assure that there be improvements in actual performance by engines certifying to the standard. We believe that such assurance is a necessary and reasonable balance for the three year additional lead time for meeting the aftertreatment-based standard. There were no adverse comments on conditioning the extension in this manner.

In the alternative, a manufacturer may elect to skip the interim standard completely. However, manufacturers choosing this option will receive only one additional year for compliance with the 0.02 g/bhp-hr standard (*i.e.* compliance in 2013, rather than 2012). These engines would already have had eight years of lead time to prepare for the PM standard without any diversion of resources to meet an interim PM standard, so that an extension of longer than one year would not be appropriate, within the meaning of section 213(b) of the Act. In addition, structuring the extension in this way encourages small engine manufacturers to choose to meet the 2008 interim standard for PM, furthering the objective of early PM emission reductions.

• NO_X—there is no change in the NO_X standard for engines in this category, therefore no special provisions are being provided.

For engines in the 75 to 175 hp category:

• PM—a manufacturer may elect to delay compliance with the standard for up to three years.

• NO_X—a manufacturer may elect to delay compliance with the standard for up to three years.

These provisions are also set out below in the following table (in all instances, these engines must meet the previously applicable standards as set out in § 1039.104 (c):

Horsepower category		Provision
<25 hp	NO_X	No special provisions are being provided.
	PM	Manufacturers may delay compliance with the standard for three years.
	NO_X	Manufacturers may delay compliance with the standard for three years.
25–50 hp	PM	Manufacturers must comply with the interim standards in 2008, and may delay compliance with the 2013 Tier 4 requirements (0.02 g/bhp-hr PM standard) for three years.
	NO_X	No special provisions are being provided.
		Manufacturers must comply with the interim Tier 4 requirements in 2008, without the use of credits, and may elect to delay compliance with the 2013 Tier 4 requirements (0.02 g/bhp-hr PM standard) for three years
50–75 hp	PM	—OR—
		Manufacturers may skip the interim standard completely, and will receive an additional year for compliance with the 0.02 g/bhp-hr PM Tier 4 standard (*i.e.* compliance in 2013, rather than 2012).
75–175 hp	NO_X	Manufacturers may delay compliance with the standard for three years.
	PM	Manufacturers may delay compliance with the standard for three years.

b. Hardship Provisions for Small Business Engine Manufacturers

i. Panel Recommendations and Our Proposals

The Panel recommended two types of hardship provisions for small business engine manufacturers. These provisions would allow for relief in the following cases:

• A catastrophic event, or other extreme unforseen circumstances, beyond the control of the manufacturer that could not have been avoided with reasonable discretion (*i.e.*, fire, tornado, supplier not fulfilling contract, etc.); and

• The event where a manufacturer has taken all reasonable business, technical, and economic steps to comply but cannot.

The Panel believed that either hardship relief provision would provide lead time for up to 2 years, and that a manufacturer should have to demonstrate to EPA's satisfaction that failure to sell the noncompliant engines would jeopardize the company's solvency. EPA may also require that the manufacturer make up the lost environmental benefit.

We proposed the Panel recommendations for hardship provisions for small business engine manufacturers. While perhaps ultimately not necessary given the phase-in schedule discussed above, we stated that such provisions provide a useful safety valve in the event of unforeseen extreme hardship.

ii. What We Are Finalizing

We received two comments on the provisions for small business engine manufacturers. SBA's Office of Advocacy commented that the rule would impose significant burdens on a substantial number of small entities with little corresponding environmental benefit; and further, that we should exclude smaller engines (those under 75 hp) from further regulation in order to comply with the Regulatory Flexibility Act and fulfill the requirement of reducing the burden on small engine classes. As proposed, we are not adopting standards based on performance of NO_X aftertreatment technologies for engines under 75 hp. As described in more detail in section II of this preamble, the Summary and Analysis of Comment Document, and the RIA, we have found no factual basis supporting the assertion that standards for PM for engines between 25 and 75 hp based on use of advanced aftertreatment impose costs out of relation to environmental benefit, have a disproportionate impact on small businesses, or are otherwise inappropriate. In fact, it is our finding that these standards for PM are "appropriate" within the meaning of section 213(a)(4) of the Clean Air Act, and that PM standards for these engines not based on performance of advanced aftertreatment would be inappropriate as failing to reflect standards based on available treatment for these engines (taking into account costs, noise, safety, and energy factors). We received no adverse comments from small business engine manufacturers on the proposed transition provisions for those manufacturers.[69] Accordingly, we are finalizing the small business engine manufacturer hardship provisions that we proposed in the NPRM (as recommended by the Panel). We believe that these provisions will provide adequate regulatory flexibility for these manufacturers, while remaining consistent with the requirements of section 213(a)(4) and 213(b) of the Clean Air Act.

c. Other Small Business Engine Manufacturer Issues

i. Panel Recommendations and Our Proposals

The Panel also recommended that an ABT program be included as part of the overall rulemaking program. In addition, the Panel suggested that EPA take comment on including specific ABT provisions for small business engine manufacturers. We proposed an ABT program for all engine manufacturers, with this program retaining the basic structure of the current nonroad diesel ABT program.

We did not include small business engine manufacturer-specific ABT

[69] The one comment that we received supported the provisions proposed for small business engine manufacturers.

provisions in the proposal. Discussions during the SBAR process indicated that small volume manufacturers would need extra time to comply due to cost and personnel constraints, and there is little reason to believe that small business manufacturer specific ABT provisions could create an incentive to accelerate compliance.

ii. What We Are Finalizing

As discussed above in section III.B, we are finalizing an ABT program in today's action similar to that already in place for nonroad engine manufacturers. We have also made a number of changes to accommodate implementation of these new emission standards.

2. Small Nonroad Diesel Equipment Manufacturers

a. Transition Provisions for Small Business Equipment Manufacturers

i. Panel Recommendations and Our Proposals

The Panel recommended that we adopt the transition provisions described below for small business manufacturers and small business importers of nonroad diesel equipment. These transition provisions are similar to those in the Tier 2/3 rule (see 40 CFR 89.102). The recommended transition provisions were as follows:

- Percent-of-Production Allowance: Over a seven model year period, equipment manufacturers may install engines not certified to the new emission standards in an amount of equipment equivalent to 80 percent of one year's production. This is to be implemented by power category with the average determined over the period in which the flexibility is used.
- Small Volume Allowance: A manufacturer may exceed the 80 percent allowance in seven years as described above, provided that the previous Tier engine use does not exceed 700 total over seven years, and 200 in any given year. This is limited to one family per power category. Alternatively, the Panel recommended, at the manufacturer's choice by hp category, a program that eliminates the "single family provision" restriction with revised total and annual sales limits as shown below:

—For categories ≤175 hp–525 previous Tier engines (over 7 years) with an annual cap of 150 units (these engine numbers are separate for each hp category defined in the regulations)

—For categories of > 175 hp–350 previous Tier engines (over 7 years) with an annual cap of 100 units (these engine numbers are separate for each hp category defined in the regulations).

The Panel recommended that EPA seek comment on the total number of engines and annual cap values listed above. In contrast to the Tier 2/Tier3 rule, the SBA Office of Advocacy expected the transition to the Tier 4 technology will be more costly and technically difficult. Therefore, the small business equipment manufacturers may need more liberal flexibility allowances especially for equipment using the lower hp engines. The Panel's recommended flexibility may not adequately address the approximately 50 percent of small business equipment models where the annual sales per model is less than 300 and the fixed costs are higher. Thus, the SBA Office of Advocacy and the Office of Management and Budget (OMB) Panel members recommended that comment be sought on implementing the small volume allowance (700 engine provision) for small business equipment manufacturers without a limit on the number of engine families which could be covered in any hp category.

- Due to the changing nature of the technology as the manufacturers make the transition from Tier 2 to Tier 3 and Tier 4, the Panel recommended that the equipment manufacturers be permitted to borrow from the Tier3/Tier 4 flexibilities for use in the Tier 2/Tier 3 time frame.
- Lastly, the Panel recommended proposing a continuation of the current transition provisions, without modifications to the levels or nature of the provisions, that are available to these manufacturers.

To maximize the likelihood that the application of these provisions will result in the availability of previous Tier engines for use by the small business equipment manufacturers, the Panel recommended that—similar to the application of flexibility options that are currently in place—these provisions should be provided to all equipment manufacturers.[70]

We did in fact propose the Percent-of-Production and Small Volume Allowances listed above for all equipment manufacturers, and explicitly took the Panel report into account in making that proposal. We also requested comment on a number of additional items, some of which were proposed by the Panel (see section III.B above).

[70] The Panel recognized that, similar to the Tier 2/3 standards, it may be necessary to provide transition provisions for all equipment manufacturers, not just for small entities, and the Panel recommended that this be taken into account.

ii. What We Are Finalizing

We are finalizing the Percent-of-Production and Small Volume Allowances for all equipment manufacturers, with a few changes. Some non-small equipment manufacturers commented that the small-volume provision should enable manufacturers to exempt up to 700 pieces of equipment over a seven-year period, with no engine family restriction. As explained earlier in section III.B.2.c, we are finalizing provisions that allow manufacturers to choose between two options: (a) Manufacturers would be allowed to exempt 700 pieces of equipment over seven years, within one engine family; or (b) manufacturers using the small-volume allowance could exempt 525 machines over seven years (with a maximum of 150 in any given year) for each of the three power categories below 175 horsepower, and 350 machines over seven years (with a maximum of 100 in any given year) for the two power categories above 175 horsepower. Concurrent with the revised caps, manufacturers could exempt engines from more than one engine family under the small-volume allowance program. As explained earlier, based on sales information for small businesses, we estimated that the alternative small-volume allowance program to include lower caps and allow manufacturers to exempt more than one engine family would keep the total number of engines eligible for the allowance at roughly the same overall level as the 700–unit program. The Agency believes that these provisions will afford manufacturers the type of transition leeway recommended by the Panel. Further, these transition provisions could allow small business equipment manufacturers to postpone any redesign needed on low sales volume or difficult equipment packages, thus saving both money and strain on limited engineering staffs. Within limits, small equipment manufacturers would be able to continue to use their current engine/equipment configuration and avoid out-of-cycle equipment redesign until the allowances are exhausted or the time limit passes.

During the SBREFA Panel process, the Panel discussed the possible misuse of the transition provisions by using them as a loophole to enter the nonroad diesel equipment market or to gain unfair market position relative to other manufacturers. See 68 FR at 28481. EPA was concerned that importers of equipment from a foreign equipment manufacturer could, as a group, import more exempted equipment from that foreign manufacturer than 80 percent of that manufacturer's production for the United States market or more than the small volume allowances identified in the transition provisions. This would create a potentially significant disparity between the treatment of foreign and domestic equipment manufacturers. EPA did not intend this outcome, and did not believe it was needed to provide reasonable lead time to foreign equipment manufacturers. The Panel recognized that this was a possible problem, and believed that a requirement that small equipment manufacturers and importers must have reported equipment sales using certified engines in model year 2002 or earlier in order to be eligible to access the transition provisions was sufficient to alleviate this problem. Upon further analysis during the development of the proposal, EPA decided to limit the availability of transition provisions to entities that install engines and have primary responsibility for designing and manufacturing equipment and included such a requirement in the proposal. Id. at 28477. Therefore, a company that only imported equipment, and had no involvement in the actual manufacturing of the equipment, would be ineligible to access the transition provisions. As described in section III.B.4, we are finalizing the proposed requirements associated with the use of transition provisions by foreign importers. Therefore, we no longer believe it is necessary to have a separate requirement that small equipment manufacturers and importers have reported equipment sales using certified engines in model year 2002 or earlier, and therefore are not finalizing this redundant provision.

We are also finalizing the Panel's recommendation that equipment manufacturers be allowed to borrow from Tier 4 flexibilities in the Tier2/3 time frame. See the more extended discussion on this issue in section III.B.2.d above.

We are not finalizing the Panel recommendation of a provision allowing small manufacturers to request limited "application specific" alternative standards for equipment configurations which present unusually challenging technical issues for compliance. We do not believe that the need for such a provision has been established, and further, it could likely provide more lead time than can be justified, and undermine emission reductions which are achievable. Moreover, no participant in the SBAR process or during the public comment period offered any empirical support that such a problem even exists. Nor have such issues been demonstrated (or raised) by equipment manufacturers, small or large, in implementing the current nonroad standards. In addition, we believe that any application-specific difficulties can be accommodated by the transition provisions the Agency is proposing including ABT.

We are also finalizing two additional provisions for all equipment manufacturers that small business equipment manufacturers may take advantage of. These provisions are the Technical Hardship Provision and the Early Tier 4 Engine Incentive Program. Both provisions are discussed in greater detail in sections III.B.2.b and e above.

b. Hardship Provisions for Small Business Equipment Manufacturers

i. Panel Recommendations and Our Proposals

The Panel also recommended that two types of hardship provisions be extended to small business equipment manufacturers. These provisions would allow for relief in the following cases:

- A catastrophic event, or other extreme unforseen circumstances, beyond the control of the manufacturer that could not have been avoided with reasonable discretion (*i.e.*, fire, tornado, supplier not fulfilling contract, etc.).
- The event where a manufacturer has taken all reasonable business, technical, and economic steps to comply but cannot. In this case relief would have to be sought before there is imminent jeopardy that a manufacturer's equipment could not be sold and a manufacturer would have to demonstrate to the Agency's satisfaction that failure to get permission to sell equipment with a previous Tier engine would create a serious economic hardship. Hardship relief of this nature cannot be sought by an "integrated" manufacturer (one which also manufactures the engines for its equipment).

We proposed that the hardship provisions recommended by the Panel be extended to small business equipment manufacturers in addition to the transition provisions described above. We also requested comment on the stipulation that, to be eligible for these hardship provisions (as well as the other proposed transition provisions), equipment manufacturers and importers must have reported equipment sales using certified engines in model year 2002 or earlier.

ii. What We Are Finalizing

We are finalizing the Panel-recommended hardship provisions for small business equipment manufacturers (which are the same provisions that are being adopted for all equipment manufacturers).

EPA also received comment concerning the situation faced by small business equipment manufacturers using engines in the 25–50 horsepower range. The concern was raised that small businesses in this power grouping will face a greater relative burden in designing equipment for engines with aftertreatment, and that they may need additional lead time beyond that provided by the small volume allowances. EPA believes that in general the small volume allowances should provide reasonable lead time opportunity for these manufacturers, but recognizes that there may be individual cases where more lead time would be appropriate for small business manufacturers in this power category. EPA is therefore adopting a technical hardship provision similar to that adopted for the percent of production allowance. Small business manufacturers using engines in the 25–50 hp range could petition EPA to approve additional needed lead time in appropriate, individualized circumstances, based on a showing of extreme technical or engineering hardship as provided in 40 CFR 1039.625(m). EPA could approve additional small volume allowances, up to a total number of 1100 units. This total number includes the allowances that are already available under the rule without request. These additional allowances could only be used for engines in the 25–50 horsepower range, and could only be approved for qualifying small business equipment manufacturers. The limitations on the use of small volume allowances (such as when allowances may only be used within a single engine family and the annual limits) continue to apply to the standard allowances (that are available under the rule without request). Finally, any additional allowances granted under this provision would have to be used within 36 months after the transition flexibility period commences for these engines. The additional allowances would not be subject to the annual limits noted earlier but they could only be used after the maximum amount of standard allowances are used in a given year (*e.g.*, a manufacturer using the 700 unit allowance would have to use 200 of their standard allowances for that year before they could use any of the additional allowances granted by EPA under this technical hardship provisions).

EPA recognizes that it is important to facilitate the process for small business equipment manufacturers to seek such approval, and intends to work with small manufacturers so that any transaction costs for them or for EPA can be minimized. For example, EPA could consider at one time a common request from similarly situated small business equipment manufacturers, as long as all of the necessary individual information for each applicant were provided. Given that information in such an application would still be both company- and fact-specific (and likely confidential as well), and that the criteria for relief as well as the scope of appropriate relief are case-specific, we would necessarily evaluate and decide whether or not to approve additional small volume allowances on a company-by-company, case-by-case basis.

For a detailed description of the comments received on small business engine and equipment manufacturer issues, please refer to the Summary and Analysis of comments, which is a part of the rulemaking record (E-DOCKET number OAR–2003–0012, and legacy docket number A–2001–28). A summary of the SBREFA process is located in section X.C of this preamble.

D. Certification Fuel

It is well-established that measured emissions may be affected by the properties of the fuel used during the test. For this reason, we have historically specified allowable ranges for test fuel properties such as cetane number and sulfur content. These specifications are intended to represent most typical fuels that are commercially available in use. This helps to ensure that the emissions reductions expected from the standards occur in use as well as during emissions testing.

We are establishing all 6 provisions that we proposed related to the sulfur content of fuel used in conducting nonroad diesel engine emissions testing:

- 300–500 ppm for model year 2008 to 2010 engines,
- 7–15 ppm for 2011 and later model year engines,
- Extension through model year 2007 of the maximum 2000 ppm specification for Agency testing on pre-Tier 4 engines,
- 7–15 ppm for 2007–2010 model year engines that use sulfur-sensitive technology,
- 7–15 ppm for 2008–2010 model year engines under 75 hp,
- 300–500 ppm for some model year 2006–2007 engines at or above 100 hp.

The last 3 of these provisions are at the certifying manufacturer's option, and involve additional measures that the manufacturer must take to help ensure that the specified fuel is used in the field. The below discussion provides more detail on each of these provisions.

We received very little comment on our proposed certification fuel provisions. Detroit Diesel commented that we should set a maximum sulfur specification of 500 ppm for Tier 3 engines, which we are in fact doing beginning in model year 2008 after this fuel is introduced in the nonroad market, and optionally allowing as early as 2006, the earliest Tier 3 model year, provided manufacturers take steps to encourage the use of this fuel, as discussed below.

Because we are lowering the upper limit for in-use nonroad diesel fuel sulfur content to 500 ppm in 2007, and again to 15 ppm in 2010, we are also establishing new ranges of allowable sulfur content for testing. These are 300 to 500 ppm (by weight) for model year 2008 to 2010 engines, and 7 to 15 ppm (by weight) for 2011 and later model year engines. We believe that these ranges best correspond to the fuels that diesel machines will potentially see in use.[71] These specifications will apply to emission testing conducted for certification, selective enforcement audits, in-use, and NTE testing, as well as any other laboratory engine testing for compliance purposes for engines in the designated model years. Any compliance testing of previous model year engines will be done with the fuels designated in our regulations for those model years. Note that, as proposed, we are allowing certification with fuel meeting the 7 to 15 ppm sulfur specification in 2010 for under 11 hp, air-cooled, hand-startable, direct injection (DI) engines certified under the optional standard provision discussed in section II.A.3.a.

It is important to note that while these specifications include the maximum sulfur level allowed for in-use fuel, we believe that it is generally appropriate to test using the most typical fuels. As for highway fuel, we expect that, under the 15 ppm maximum sulfur requirement, refineries will typically produce diesel fuel with about 7 ppm sulfur, and that the fuel could have slightly higher sulfur levels after distribution. Thus, we expect that we will use fuel having a sulfur content between 7 and 10 ppm sulfur for our emission testing. This is the same as the range we indicated will be used for heavy-duty diesel engine (HDDE) engine testing in model year 2007 and later (66 FR 5002, January 18, 2001). As with the highway fuel, should we determine that the typical in-use nonroad diesel fuel has significantly more sulfur than this, we would adjust this target upward.

We are also adopting two options for early use of the new 7 to 15 ppm sulfur diesel test fuel. The first will be available beginning in the 2007 model year for engines employing sulfur-sensitive technology. (Model year 2007 coincides approximately with the introduction of 15 ppm highway fuel.) This allowance to use the new fuel in model years before 2011 will only be available for engines which the manufacturer demonstrates will be operated in use on fuel with 15 ppm sulfur or less. Any testing that we perform on these engines will also use fuel meeting this lower sulfur specification. This optional certification fuel provision is intended to encourage the introduction of low-emission diesel technologies in the nonroad sector. These engines will be able to use the lower sulfur fuel throughout their operating life, given the early availability of this fuel under the highway program, and the assured availability of this fuel for nonroad engines by mid-2010.

Considering that our Tier 4 program will subject engines under 75 hp to new emission standards in 2008 when 15 ppm maximum sulfur fuel will be readily available from highway fuel pumps (and will enter the nonroad fuel market shortly after in 2010), we believe it is appropriate to provide a second, less proscriptive, option for use of 15 ppm sulfur certification fuel. This option will be available to any manufacturers willing to take extra steps to encourage the use of this fuel before it is required in the field. We are allowing the early use of 15 ppm certification fuel for 2008–2010 engines under 75 hp, provided the certifying manufacturer ensures that ultimate purchasers of equipment using these engines are informed that the use of fuel meeting the 15 ppm specification is recommended, and also recommends to equipment manufacturers buying these engines that labels be applied at the fuel inlet to remind users of this recommendation. This option does not apply to those 50–75 hp engines not being certified to the 0.22 g/bhp-hr PM standard, under the manufacturers' option discussed in section II.A.1.a.

We believe that there may be a very small loss of emissions benefit from any of these engines for which the operator chooses to ignore the recommendation. This is because the engine manufacturer will be designing the engine to comply with the emissions standards when tested using 15 ppm fuel, potentially resulting in slightly higher emissions when it is not operated on the 15 ppm

[71] *See* 66 FR 5112–5113 (January 18, 2001) where we adopted a similar approach to certification fuels for highway heavy-duty diesel engines (HDDEs).

fuel. We also believe, however, that this is more than offset overall by the encouragement this provision provides for early use of 15 ppm fuel. We are not making this option available for engine designs employing oxidation catalysts or other sulfur-sensitive exhaust emission control devices except under the more restrictive provision for early use of 15 ppm fuel described above, involving a demonstration by the manufacturer that the fuel will indeed be used. Because these devices could potentially have very high sulfur-to-sulfate conversion rates (see section II.B.4 and 5 above), and because very high-sulfur fuels will still be available to some extent, we believe that allowing this provision for these engines would risk very high PM emissions until the 15 ppm nonroad fuel is introduced. We are not making this second early 15 ppm test fuel option available for engines not subject to a new Tier 4 standard in 2008 as these engines should already be designed to meet applicable standards in earlier years without need for the 15 ppm fuel.

We are also adopting a similar provision for use of certification fuel meeting the 300–500 ppm sulfur specification before the 2008 model year. We believe certification of model year 2006 and 2007 engines being designed without the use of sulfur-sensitive technologies to meet new Tier 2 or Tier 3 emission standards taking effect in those years (2006 for engines at or above 175 hp and 2007 for 100–175 hp engines) should be able to use this fuel, provided the certifying manufacturer is willing to take measures equivalent to those discussed above to encourage the early use of this fuel (a recommendation to the ultimate purchaser to use fuel with 500 ppm maximum sulfur and a recommendation to equipment manufacturers to so label their equipment).

The widespread availability of 500 ppm sulfur highway fuel, the short time that these 2006 and 2007 engines could use higher sulfur fuels if an operator were to ignore the recommendation, and the eventual use of 15 ppm sulfur fuel in most of these engines for most of their operating lives, gives us confidence that this provision to encourage early use of lower sulfur fuel will be beneficial to the environment overall. As with the change to 300–500 ppm cert fuel for model years 2008–2010, engine manufacturers will design their engines to comply based on the test fuel specifications for certification and compliance testing. The change from a fuel specification for compliance testing that ranges up to 2000 ppm sulfur for Tier 2 and 3 engines to a specification of 500 ppm sulfur maximum could have some limited effect on the emissions control designs used on these Tier 2 and 3 engines, in that it will be slightly easier to meet the Tier 2 and 3 standards using the lower sulfur test fuel. In general, it is reasonable to set specifications of test fuel reflecting representative in-use fuels, and here the engines are expected to be using fuel with sulfur levels of 500 ppm or lower until 2010, and 15 ppm or lower after that. In this case, any impact on expected engine emissions from this change in test fuel for Tier 2 and 3 is expected to be slight.

We note that under current regulations manufacturers are already allowed to conduct testing with certification fuel sulfur levels as low as 300 ppm. The additional provision for early use of 300–500 ppm sulfur test fuel will, however, result in any compliance testing conducted by the Agency being done with fuel meeting the 300–500 ppm specification. Likewise choice of the option for early use of 15 ppm sulfur test fuel would result in any Agency testing being done using that fuel. However, under both of these early certification fuel options involving a recommended fuel use provision, the Agency will not reject engines from in-use testing for which there is evidence or suspicion that the engine had been fueled at some time with higher sulfur fuel.

Finally, we are extending a provision adopted in the 1998 final rule (63 FR 56967, October 23, 1998). In that rule we set a 2000 ppm upper limit on the test fuel sulfur concentration for any testing to be performed by the Agency on Tier 1 engines under 50 hp and Tier 2 engines at or above 50 hp. We did not extend this provision to later model year engines at that time because we felt that more time was needed to assess trends in fuel sulfur levels for fuels used in nonroad diesels. At this time we are not aware of any additional information that would indicate that a change in this test specification is warranted. More importantly, because the fuel regulation we are adopting will make 500 ppm maximum sulfur nonroad diesel fuel available by mid-2007, Tier 3 engines at or above 50 hp (which phase in beginning in 2006) will be in the field for only 1½ years prior to the in-use introduction of 500 ppm fuel, and Tier 2 engines under 50 hp (which phase in beginning in 2004) will be in the field for at most 3½ years prior to this time. We believe it is appropriate to avoid adding the unnecessary complication of frequent multiple changes to the test fuel specification. We are therefore extending the 2000 ppm limit to testing conducted on engines until the 2008 model year when the 500 ppm maximum test fuel sulfur level takes effect as discussed above.

E. Temporary In-Use Compliance Margins

The Tier 4 standards will be challenging for diesel engine manufacturers to achieve, and will require manufacturers to develop and adapt new technologies for a large number and wide variety of engine platforms. Not only will manufacturers be responsible for ensuring that these technologies enable compliance with Tier 4 standards at the time of certification, they will also have to ensure that these technologies continue to be highly effective in a wide range of in-use environments so that their engines will comply in use when tested by EPA. Furthermore, for the first time, these nonroad diesel engines will be subject to transient emissions control requirements and to NTE standards.

However, in the early years of a program that introduces new technology, there are risks of in-use compliance problems that may not appear in the certification process or during developmental testing. Thus, we believe that for a limited number of model years after new standards take effect it is appropriate to adjust the compliance levels for assessing in-use compliance for diesel engines equipped with high-efficiency exhaust emissions control devices. This provides assurance to the manufacturers that they will not face recall if they exceed standards by a small amount during this transition to clean technologies. This approach is very similar to that taken in the light-duty highway Tier 2 final rule (65 FR 6796, February 10, 2000) and the highway heavy-duty rule (66 FR 5113–5114, January 18, 2001), both of which involve similar approaches to introducing the new technologies. In fact, the similarities of nonroad diesel engines and expected Tier 4 control technologies to counterpart engines and technologies for heavy-duty highway diesel engines led us to model the proposed Tier 4 add-on provisions after the 2007 heavy-duty highway diesel program, with add-on levels chosen to be roughly equivalent to the levels adopted in the highway rule.

Comments on the proposal were received from engine manufacturers, requesting changes that would make the temporary in-use adjustments more closely parallel the highway requirements. Specifically, they requested: (1) Providing two full model years of applicability following the completion of standards phase-in for the

75–175 hp category, as was proposed for the other power categories, (2) adjusting the NO_X threshold for applicability of the provisions to a level 8% above the split family standard, (3) adopting 3 levels of add-ons based on how many hours the test engine had been used, with cutpoints at 2000 and 3400 hours, and (4) a 25% upward adjustment to the add-on levels. We agree that these changes would result in a closer approximation to the highway program. Our goal in proposing provisions somewhat different from the highway program was to avoid unnecessary complexity. However, we believe that maintaining consistency with the highway program is a more important goal and the manufacturers' suggested changes do not overly complicate the program, and so we have decided to make these changes.

We note too that changes we are making to the Tier 4 program for engines over 750 hp necessitate other changes to the in-use add-on program for these engines as well. Specifically, these are the extension of model year applicability to 2016, two years after the final Tier 4 standards take effect, and the clarification of what PM thresholds apply for engines used in generator sets and for other engines.

Table III.E–1 shows the in-use adjustments that we will apply. These in-use add-on levels will be applied only to engines certified in the indicated model years and having FELs (or certifying to standards without FELs) at or below the specified threshold levels. These adjustments are added to the appropriate FELs (see section III.A) or, for engines certified to the standards without the use of ABT program credits, to the standards themselves, in determining the in-use compliance level for a given in-use hours accumulation on the engine being tested. Note that the PM adjustment is the same for all in-use hours accumulation. Note also that, because the standards in the regulations are expressed in g/kW-hr, the adjustments included in the regulations are set at levels that make the resulting adjusted in-use standard equivalent in stringency to the standards in this preamble (expressed in g/bhp-hr) adjusted by the values in Table III.E–1 (also expressed in g/bhp-hr).

Note too that, as part of the certification demonstration, manufacturers will still be required to demonstrate compliance with the unadjusted Tier 4 certification standards using deteriorated emission rates. Therefore, the manufacturer will not be able to use these in-use standards as the design targets for the engine. They will need to project that most engines will meet the standards in-use without adjustment. The in-use adjustments will merely provide some assurance that they will not be forced to recall engines because of some small miscalculation of the expected deterioration rates.

TABLE III.E–1.—ADD-ON LEVELS USED IN DETERMINING IN-USE STANDARDS

Engine power	Model years	NO_X		PM
		Add-on level [a] (g/bhp-hr)	For operating hours	Add-On level [b] (g/bhp-hr)
25 ≤ hp <75 (19 ≤ kW <56)	2013–2014	none		0.01
75 ≤ hp <175 (56 ≤ kW <130)	2012–2016	0.12 0.19 0.25	≤ 2000 2001–3400 > 3400	0.01
175 ≤ hp ≤750 (130≤ kW ≤560)	2011–2015	0.12 0.19 0.25	≤ 2000 2001–3400 > 3400	0.01
hp >750 (kW >560)	2011–2016	0.12 0.19 0.25	≤ 2000 2001–3400 > 3400	0.01

Notes:
[a] Applicable only to those engines certifying to standards or with FELs at or below 1.6 g/bhp-hr NO_X.
[b] Applicable only to those engines certifying to standards or with FELs at or below the filter-based Tier 4 PM standards (0.01 g/bhp-hr for 75–750 hp engines, 0.02 g/bhp-hr for 25–75 hp engines and for >750 hp engines in generator sets, and 0.03 g/bhp-hr for all other >750 hp engines).

F. Test Cycles

1. Transient Test

In the 1998 final rule that set new emission standards for nonroad diesel engines, EPA expressed a concern that the steady-state test cycles used to demonstrate compliance with emission standards did not adequately reflect transient operation as many nonroad engines are used in applications that are largely transient in nature and would not therefore yield adequate control of emissions in use (63 FR 56984, October 23, 1998). Although we were not prepared to adopt a transient test at that time, we announced our intention in that final rule to move forward with the development of such a test. This development progressed steadily and has resulted in the creation of the Nonroad Transient Composite (NRTC) test cycle which we are adopting in our Tier 4 nonroad diesel program. The NRTC cycle supplements the existing nonroad steady-state test requirements. Thus, most nonroad engines subject to today's Tier 4 standards will be required to certify using both of these tests.[72] The NRTC cycle captures transient emissions over much of the typical nonroad engine operating range, and thus helps to ensure effective control of all regulated pollutants. The speed and load operating schedule for EPA's NRTC test cycle is described in regulations at 40 CFR 1039.505. A detailed discussion of the transient test cycle and its derivation is contained in chapter 4.2 of the RIA for this rule.

We expect that this transient test requirement will significantly reduce real world emissions from nonroad diesel equipment. Proper transient

[72] See EPA Dear Manufacturer Letter VPCD–98–13, "Heavy-duty Diesel Engines Controlled by Onboard Computers: Guidance on Reporting and Evaluating Auxiliary Emission Control Devices and the Defeat Device Prohibition of the Clean Air Act," October 15, 1998 and EPA Advisory Circular 24–3, "Implementation of Requirements Prohibiting Defeat Devices for On-Highway Heavy-Duty Diesel Engines." A copy of both of these documents is available in EPA Air Docket A–2001–28.

operation testing captures engine emissions from the broad range of engine speed and load combinations that the engine may attain in-use, while the steady-state emission test characterizes emissions at the few isolated operating points that may be typical for that family of engines. Testing for transient emissions will likewise identify emissions which result from the operation of the engine, as with speed and load changes, turbocharger lag, etc.

In keeping with our goal to maximize the harmonization of emissions control programs as much as possible, we have developed this cycle in collaboration with nonroad engine manufacturers and regulatory bodies, both domestic and foreign, over the last several years.[73] Further, the NRTC cycle has been introduced as a work item for possible adoption as a potential global technical regulation under the 1998 Agreement for Working Party 29 at the United Nations.[74]

EPA's nonroad transient test will apply (with one exception noted below) to a nonroad diesel engine when that engine must first show compliance with EPA's Tier 4 PM and NO_X+NMHC emissions standards which are based on the performance of the advanced post-combustion emissions control systems (*e.g.* catalyzed-diesel particulate filters and NO_X adsorbers). This is 2011 for engines at 175 hp–750 hp, 2012 for 75–175 hp engines (2012, as well, for 50–75 hp engines made by a manufacturer choosing the option to not comply with the 2008 transitional PM standard.), and 2013 for engines under 75 hp. The transient test cycle will not apply to engines greater than 750 hp. Specific provision is made for engines under 25 hp for PM and under 75 hp for NO_X (which are not based on performance of advanced aftertreatment). Constant-speed, variable-load engines of any horsepower category currently certify to EPA's 5–Mode Steady State duty cycle and are not subject to transient duty cycle testing. As with current nonroad diesel standards, today's Tier 4 emission standards will apply to certification, Selective Enforcement Audits (SEAs) and to recall testing of equipment in-use for all engines subject to these standards.

TABLE III.F–1.—IMPLEMENTATION MODEL YEAR FOR NONROAD TRANSIENT TESTING

Power category	Transient test implementation model years
< 25 hp	2013
25 ≤ hp < 75	2013
75 ≤ hp < 175	2012
175≤ hp < 750	2011

In addition, any engines for which an engine manufacturer (see section III.M) or equipment maker (see section III.B.2.c) claims credit under the incentive program for early-introduction engines will have to be certified to that program's standards under applicable Tier 4 nonroad transient and steady-state duty cycles, *e.g.*, NRTC, 8-mode and 5-mode steady-state cycles. In turn, any 2011 or later model year engine that uses these engine count-based credits will not need to demonstrate compliance under the NRTC cycle. Engines in any power category certified to an alternate NO_X standard are all subject to the transient test requirement, as they clearly will be substantially redesigned to achieve Tier 4 compliance, regardless of whether or not they use high-efficiency exhaust emission controls. *See* section II.A.1.c, above.

We solicited comment on whether the transient duty cycle should apply to NO_X emissions from phase-out engines (68 FR 28484, May 23, 2003) and received comment from EMA. EMA prefers that the transient cycle only be applicable to PM emission testing and not for NO_X, NMHC and CO for phase-out engine families. They believe that the application of the transient NRTC and standards could result in the need to redevelop the NO_X/NMHC/CO emission control systems used for their members' compliance with Tier 3 standards.

We essentially agree with this comment to the extent that phase-out engines do not include improvements in gaseous pollutant emission control (*i.e.* they remain essentially Tier 3 engines for emissions other than PM). Imposing new requirements with respect to these engines' gaseous pollutant emissions could divert resources inappropriately. The rule therefore states (in 40 CFR 1039.102 (a)(2)) that gaseous pollutant emissions from these engines are not subject to transient testing standards. This would not apply if a manufacturer declares a new NO_X+NMHC FEL for the engine family (since the manufacturer would then already be choosing to alter these engines' performance with respect to gaseous pollutant emissions).[75]

Transient testing standards do apply with respect to PM emissions from phase-out engines, however. The reason is evident: the PM standard for phase-out (and phase-in) engines is based on performance of aftertreatment, so the full complement of test cycles (NTE as well as transient testing) should apply. A consequence of this is that phase-out engines will generally be tested over the transient cycle, since they must do so with respect to PM emissions. We repeat, however, that although the engines will do transient testing, only PM (and not gaseous pollutants) is subject to the transient test standard.

In addition, manufacturers choosing to certify engines under 750 hp using alternative FEL caps during the first four years that the alternative caps are available (see section III.A.i.2 above) will not be subject to the transient or NTE standards. However, to properly account for the transient effects when calculating credits, we are requiring the FELs of such engines to be adjusted upwards by applying a Temporary Compliance Adjustment Factor (TCAF)[76]. See 40 CFR 1039.104 (g) (2).

Even though we are requiring that NRTC testing start when the PM aftertreatment-based standards take effect, one should not infer that the NRTC is directed at solely (or even primarily) at PM control. In fact, we believe that advanced NO_X emission controls may be even more sensitive to transient operation than PM filters, since the PM filters ordinarily operate equally effectively in all operating modes, as noted earlier. It is, however, our intent that the control of emissions during transient operation be an integral part of Tier 4 engine design considerations. We have therefore chosen to apply the transient test requirement starting with the PM filter-based Tier 4 PM standards as these standards precede or accompany the earliest Tier 4 NO_X or NMHC standards in all power categories except engines over 750 hp.

As EPA is not promulgating PM filter-based standards for engines below 25 hp in today's rulemaking, we are likewise not requiring these engines to be tested

[73] Letter from Jed Mandel of the Engine Manufacturers Association to Chet France of U.S. EPA, Office of Transportation and Air Quality, "Development of appropriate transient test cycle for variable speed land-based compression ignition non-road engines," Air Docket A–2001–28, II–B–33.

[74] Informal Document No.2, ISO—45th GRPE, "Proposal for a Charter for the Working Group on a New Test Protocol for Exhaust Emissions from Nonroad Mobile Machinery," Jan. 13–17, 2003, Air Docket A–2001–28, document II–A–171.

[75] Please note that this discussion does not apply to engines certifying to the alternative NO_X phase-in standards, which engines are required to meet transient and NTE requirements for gaseous pollutants (as well as all other requirements that would apply to phase-in engines). See discussion at II.A.2.c; also please note that these engines are expressly not defined as phase-out engines in the rules; see section 1039.801 and 1039.102 (e).

[76] As noted elsewhere, the TCAFs are derived identically to the Transient Adjustment Factor used in the NONROAD emissions model.

over the NRTC test cycle until model year 2013. More broadly, though we intend for transient emissions control to be an integral part of Tier 4 design considerations, we do not believe it appropriate to mandate compliance with the transient test for the engines under 50 hp which are subject to PM standards in 2008. We recognize that transient emission testing, though routine in highway engine programs, involves a fair amount of laboratory equipment and new expertise in the nonroad engine certification process. As with the transfer of advanced emission control technology itself, we believe that the transient test requirement should be implemented first for larger displacement engines. These engines are more likely to be made by manufacturers who provide engines to the on-highway market and therefore have had prior on-highway engine development and certification experience. We do not believe that the smaller engines should be the power categories first charged with implementing the new transient test, as early as 2008, especially because manufacturers of these engines do not generally make highway engines and are neither as experienced nor as well-equipped as their larger engine manufacturer counterparts at conducting transient cycle testing. However, to encourage earlier transient emission control in these engines, EPA will allow manufacturers of engines below 25 hp to submit data describing emission levels for their engines over the appropriate certification transient duty cycle beginning in model year 2008. We extend this option as well to manufacturers of 25–50 hp engines, subject to those engines meeting the Tier 4 transitional PM standard in 2008. Should a manufacturer choose to submit data in the 2008–2011 time frame, prior to required certification data submissions, that transient data will not be used for compliance enforcement.

EPA requested comment on whether engines greater than 750 hp should be subject to the transient cycle, noting concerns of technical difficulties and cost for these engines (68 FR 28484, May 23, 2003). STAPPA–ALAPCO and other agencies representing the States' interests responded to EPA that all nonroad engines should be uniformly required to test their transient emissions. Likewise, they asked that the Agency not delay implementation of this particular requirement. However, at this time, the Agency is not adopting a transient emission testing requirement for engines 750 hp and over. EPA sees the burden of transient cycle testing in these very large displacement engines as being greater than the benefit of gathering transient emission measurements from them. For example, in many instances, these engines will have multiple aspiration and exhaust systems requiring a test cell designed to accommodate multiple large flow volumes in real-time on a five Hertz, or faster, basis. New transient test requirements could require manufacturers to create new or expanded testing facilities to house, prepare and run transient tests on these larger engines. The space requirements, *i.e.*, "footprint," of such facilities could make building them cost-prohibitive.

Absent transient testing, these engines will still be required to certify to both steady-state and NTE test requirements. Moreover, we are modifying the certification requirements to include additional information for engines under 750 hp. For more detail on this submission, see the discussion in section III.I of this preamble and 40 CFR 1039.205(p) of the regulations.

Finally, engines in this power category are found in a relatively small proportion of the nonroad equipment population and, despite the potential for large quantities of emissions from this class of engines during operation, units equipped with these engines have likewise been noted to contribute a small proportion of total diesel nonroad engine emissions.[77] Many of these larger-displacement engines operate predominately in a constant-speed fashion with few transient excursions, as with electric power generation sets (gen sets) which make up a significant percent of these larger engines. Many of these gen sets, too, operate on an intermittent or stand-by only basis. Indeed, as explained below, such constant-speed, variable-load engines (for example, those certifying exclusively to the 5-mode steady-state cycle) of any horsepower category are not subject to the nonroad transient test cycle.

Further, the Agency does not intend at this time to require that manufacturers use partial-flow sampling systems (PFSS) to determine PM emissions from their engines for certification. A large engine manufacturer may, however, choose to submit PM data to the Agency using PFSS as an alternative test method, if that manufacturer can demonstrate test equivalency using a paired-T test and F-Test, as outlined in regulations at 40 CFR 86.1306–07.

Transient testing requires consideration of statistical parameters for verifying that test engines adequately follow the prescribed schedule of speed and load values. The regulations in 40 CFR 1065.514, table 1, detail these statistical parameters, also known as cycle performance statistics. These values are somewhat different than the comparable values for highway diesel engines to take into account the characteristics of nonroad engine operation. The values are an outgrowth of the long development process for the NRTC test cycle, itself.

2. Cold Start Transient Testing

Nonroad diesel engines typically operate in the field by starting and warming to a point of stabilized hot operation at least once in a workday. Such "cold-start" conditions may also occur at other times over the course of the workday, such as after a lunch break. We have observed that certain test engines, which generally had emission-control technologies for meeting Tier 2 or Tier 3 standards, had elevated emission levels for about 10 minutes after starting from a cold condition. The extent and duration of increased cold-start emissions will likely be affected by changing technology for meeting Tier 4 standards, but there is no reason to believe that this effect will lessen. In fact, cold-start concerns are especially pronounced for engines with catalytic devices for controlling exhaust emissions, because many require heating to a "light-off" or peak-efficiency temperature to begin working. See, for example, RIA section 4.1.2.2 and following. EPA's highway engine and vehicle programs, which increasingly involve such catalytic devices, address this by specifying a test procedure that first measures emissions with a cold engine, then repeats the test after the engine is warmed up, weighting emission results from the two tests for a composite emission measurement.

In the proposal, we described an analytical approach that led to a weighting of 10 percent for the cold-start test and 90 percent for the hot-start test. Manufacturers pointed out that their analysis of the same data led to a weighting of about 4 percent for cold-start testing and that a high cold-start weighting would affect the feasibility of the proposed emission standards. Manufacturers also expressed a concern that there would be a significant test burden associated with cold-start testing.

[77] Memorandum from Kent Helmer to Cleophas Jackson, "Applicability EPA's NRTC cycle to Nonroad Diesel Population," Air Docket A–2001–28, document II–B–34.

Unlike steady-state tests, which always start with hot-stabilized engine operation, transient tests come closer to simulating actual in-use operation, in which engines may start operating after only a short cool-down (hot-start) or after an extended soak (cold-start). The new transient test and manufacturers' expected use of catalytic devices to meet Tier 4 emission standards make it imperative to address cold-start emissions in the measurement procedure.[78] We are therefore adopting a test procedure that requires measurement of both cold-start and hot-start emissions over the transient duty cycle, much like for highway diesel engines. We acknowledge, however, that limited data are available to establish an appropriate cold-start weighting. For this final rule, we are therefore opting to establish a cold-start weighting of 5 percent. This is based on a typical scenario of engine operation involving an overnight soak and a total of seven hours of operation over the course of a workday. Under this scenario, the 20-minute cold-start portion constitutes 5 percent of total engine operation for the day. Section II.B above addresses the feasibility of meeting the emission standards with cold-start testing. Regarding the test burden associated with cold-start testing, we believe that manufacturers will be able to take steps to minimize the burden by taking advantage of the provision that allows for forced cooling to reduce total testing time (40 CFR 1039.510(c)).

We believe the 5-percent weighting is based on a reasonable assessment of typical in-use operation and it addresses the need to design engines to control emissions under cold-start operation. We believe cold-start testing with these weighting factors will be sufficient to require manufacturers to take steps to minimize emission increases under cold-start conditions. Once manufacturers have applied technologies and strategies to minimize cold-start emissions, they will be achieving the greatest degree of emission reductions achievable under those conditions. A higher weighting factor for cold-start testing is not likely be more effective in achieving in-use emission control as new technologies will be expected to have resulted in significant control of emissions at engine startup.

However, given our interest in controlling emissions under cold-start conditions and the relatively small amount of information available in this area at this time, we intend to revisit the cold-start weighting factor for transient testing in the future as additional data become available. Since the composite transient test represents a combination of variable-speed and constant-speed operation, we would consider operation from both of these types of engines in evaluating the cold-start weighting. Also, we intend to apply the same cold-start weighting when we adopt a transient duty cycle specifically for engines certified only for constant-speed operation.

The planned data-collection effort will focus on characterizing cold-start operation for nonroad diesel equipment. The objective will be to reassess, and if necessary, redevelop a weighting factor that properly accounts for the degree of cold-start operation so that in-use engines effectively control emissions during these conditions. As we move forward with this investigation, other interested parties, including the State of California, will be invited to participate. We are interested in pursuing a joint effort, in consultation with other national government bodies, to ensure a robust and portable data set that will facilitate common global technical regulations. This effort will require consideration of at least the following factors:

- What types of equipment will we investigate?
- How many units of each equipment type will we instrument?
- How do we select individual models that will together provide an accurate cross-section of the type of equipment they represent?
- When will the program start and how long will it last?
- How should we define a cold-start event from the range of in-use operation?

We expect to complete our further evaluation of the cold-start weighting in the context of the 2007 Technology Review, if not sooner. In case changes to the regulation are necessary, this timing will allow enough time for manufacturers to adjust their designs as needed to meet the Tier 4 standards.

3. Constant-Speed Tests

The Agency proposed that engine manufacturers could certify constant-speed engines using EPA's Constant-Speed, Variable-Load (CSVL) transient duty cycle[79] as an alternative to certifying these engines under its NRTC test cycle. The CSVL transient cycle was developed to approximate the speed and load operating characteristics of many constant-speed nonroad diesel applications.[80] It, too, would have been subject to the cold-start requirement of nonroad transient test cycles as is the NRTC. However, after considerable discussion with and comment from engine manufacturers, equipment makers and other interested parties, the Agency has decided not to promulgate an alternative nonroad transient test cycle for constant-speed engines at this time. EMA, in its comments on the CSVL cycle, felt generally that: (1) The average load factor is much too low; (2) the frequency of the transient operations was too high; (3) the amplitudes of the transients were too great; and (4) the rates of transient load increase and response were too fast.

It was further noted that the CSVL test cycle is based solely upon the operation of a single, relatively small, naturally-aspirated arc welder engine, which EMA claims is a variable-speed type of engine certified generally on the 8-mode test cycle. Arc welders, Cummins noted, are not much like generator sets, which comprise around 50% of population of constant-speed engines and have a very different operation and test cycle than the typical portable generator set. Generator sets, DDC wrote, were built generally for a higher power capability at a single speed, many having larger, less-responsive turbochargers to achieve the higher brake mean effective pressure (BMEP). This made it difficult for these engines to shed load as quickly as the CSVL test cycle would require them to do. Commenters likewise wrote that the test cycle was costly and burdensome for equipment which, like generator sets, was only operated infrequently or when emergencies occurred. Some wrote that it would compromise generator set engine performance if manufacturers had to re-engineer their products to run over the CSVL test cycle, especially for larger BMEP engines. One commenter noted that these changes to nonroad engines would carry over to other stationary applications of these generator sets. A more extensive discussion of comments relating to the CSVL cycle may be read in the Summary and Analysis of Comment document for this rule.

Given these potential problems and the strong possibility of fixing them by 2007, the Agency has decided to defer adopting the CSVL test cycle here.

[78] Note that this discussion applies only to engines that are subject to testing with transient test procedures. For example, this excludes constant-speed engines and all engines over 750 hp.

[79] Two Memoranda from Kent Helmer to Cleophas Jackson, "Speed and Load Operating Schedule for the Constant Speed Variable Load (CSVL) transient test cycle," e-Docket OAR–2003–0012–0993, and "CSVL Cycle Construction," A–2001–28, II–B–50.

[80] Memorandum from Kent Helmer to Cleophas Jackson, "Brake-specific Emissions Impact of Nonroad Diesel Engine Testing Over the NRTC, AWQ, and AW1 duty cycles," Docket A–2001–28, #.

Instead, EPA with all of its stakeholders in this regard will map out a process of engine testing and analysis to better characterize constant-speed equipment in-use to design the most appropriate test cycle for the largest number of constant-speed engines. EPA undertakes this process with an eye to initiating rulemaking which would lead to promulgation of a transient cycle for constant-speed engines before the Agency's 2007 Nonroad Diesel Technical Review.

EPA defines a constant-speed engine in this regard as one which is certified to constant-speed operation, in other words, an engine which may not operate at a speed outside a single, fixed reference speed set by the engine's governor. It should be clear then that any engine for which the governor doesn't strictly limit the engine speed in-use to constant-speed operation, that engine will be subject to the NRTC. Thus, if a manufacturer's engine is certified to EPA's 8-mode steady-state test, the engine would also need to certify to the NRTC, since the 8-mode test does not limit the engine's fixed operating speed. Conversely, those manufacturers who certify their engines to EPA's constant-speed steady-state test, the 5-mode test cycle, are not required to have their engines certify to the NRTC.

By utilizing an inclusive, data-driven approach (see Summary and Analysis document for more detail), the Agency is allowing time to develop, and if appropriate, finalize and implement a test procedure that meets the needs of the Agency, manufacturers, and other parties in advance of the 2007 Technology Review. In fact, the Agency envisions constant speed variable load cycle generation to be completed by July 2005. This approach should allow the Agency to develop a testing program which ensures robust control in-use, is data-driven and remains globally harmonized. We expect to initiate this effort within 3 months of promulgation of this rule and to conclude the work on the new test cycle in enough time to promulgate it through rulemaking and to provide industry adequate lead time to implement it in an orderly manner. If we encounter unforeseen and unavoidable delays or complications in this process, we will consider approaches to control based on available data at the time of the 2007 Technology Review.

The Agency is adopting additional requirements, in conjunction with existing steady-state test requirements, which will help ensure that constant-speed nonroad diesel engines are subject to a rigorous program of in-use control of emissions and that diesel engine emissions will be controlled over a wide range of speed and load combinations. EPA is finalizing stringent nonroad NTE limits and related test procedures for all new nonroad diesel engines subject to the Tier 4 emissions standards beginning in 2011 which will supplement the existing steady-state five-mode test cycle for constant-speed application engines. NTE testing for transient operation will add further assurance that emissions from constant-speed engines within this class, which have a limited speed response in-use, are controlled under in-use operation. Typically, engines which are designed to a particular transient cycle will control emissions effectively under other types of transient operation not specifically included in that certification procedure. Engines that are capable of meeting emission standards on a constant-speed, variable-load cycle will have the transient-response characteristics that are appropriate for controlling emissions at higher engine loads and for less dynamic transient operation. EPA, engine manufacturers, and interested parties will, in the mean time, work to develop a more appropriate transient test for constant-speed engines. A transient test for this broad class of nonroad engines will ensure a robust level of emissions control in-use within the diverse population of constant-speed engines and equipment.

4. Steady-State Tests

Recognizing the variety of both power classes and work applications to be found within the nonroad equipment and engine population, and as proposed, EPA is retaining current Federal steady-state test procedures for nonroad engines. (Manufacturers are thus required to meet emission standards under steady-state conditions, in addition to meeting emission standards under the transient test cycle, whenever the transient test cycle applies.) This requirement, like NTE emission testing, is one of two tests which apply to every Tier 4 engine. Table III–2 below sets out the particular steady-state duty cycle applicable to each of the following categories: (1) Nonroad engines 25 hp and greater; (2) nonroad engines less than 25 hp; and (3) nonroad engines having constant-speed, variable-load applications, (*e.g.*, gen sets). The steady-state cycles remain, respectively, the 8-mode cycle, the 6-mode cycle and the 5-mode cycle.[81]

Steady-state test cycles are needed so that testing for certification will reflect the broad range of operating conditions experienced by these engines. A steady-state test cycle represents an important type of modern engine operation, in power and speed ranges that are typical in-use. The mid-to-high speeds and loads represented by present steady-state testing requirements are the speeds and loads at which these engines are designed to operate for extended periods for maximum efficiency and durability. Details concerning the three steady-state procedures for nonroad engines and equipment are found in regulations at 40 CFR 1039.505 and in Appendices I–III to 40 CFR part 1039.

Manufacturers will perform each steady-state test following all applicable test procedures in the regulations at 40 CFR part 1039, *e.g.*, procedures for engine warm-up and exhaust emissions measurement. The testing must be conducted with all emission-related engine control variables in the maximum NO_X-producing condition which could be encountered for a 30 second or longer averaging period at a given test point. Table III.F–2 below summarizes the steady-state testing requirements by individual engine power categories.

TABLE III.F–2.—SUMMARY OF STEADY-STATE TEST REQUIREMENTS

Nonroad engine power classes	Steady-state testing requirements		
	8-Mode cycle (C1 weighting)	6-Mode cycle (G3 weighting)	5-Mode cycle (D2 weighting)
hp < 25 (kW < 19)	applies [a]	applies [a]	applies [b]
25 ≤ hp < 75 (19 ≤ kW < 56)	applies	NA [c]	applies [b]
75 ≤ hp < 175 (56 ≤ kW < 130)	applies	NA [c]	applies [c]

[81] These three steady-state test cycles are similar to test cycles found in the International Standard ISO 8178–4:1996 (E) and remain consistent with the existing 40 CFR part 89 steady-state duty cycles.

TABLE III.F–2.—SUMMARY OF STEADY-STATE TEST REQUIREMENTS—Continued

Nonroad engine power classes	Steady-state testing requirements		
	8-Mode cycle (C1 weighting)	6-Mode cycle (G3 weighting)	5-Mode cycle (D2 weighting)
175 ≤ hp ≤ 750 (130 ≤ kW ≤ 560)	applies	NA [c]	applies [b]
hp > 750 (kW > 560)	applies	NA [c]	applies [b]

[a] Manufacturers may use either of these tests for this class of engines.
[b] For constant, or nearly constant, speed engines and equipment with variable, or intermittent, load.
[c] Testing procedures not applicable to this class of engines.

Nonroad engine manufacturers [82], have called for steady-state testing which would collect emissions continuously "in a pseudo-transient manner," proposing in effect, one-filter PM collections during a steady-state duty cycle. In response to these and other manufacturer concerns for emission variability during certification testing due to unanticipated emission control system regeneration between steady-state test modes, the Agency [83] has adopted, in its 40 CFR 1065.515 regulations, the concept of modifying EPA's 40 CFR part 89 steady-state engine certification duty cycles. The section describes ramped "modal" steady-state certification tests which would link the modes of a steady-state test together for the purpose of collecting a continuous stream of engine emissions. These tests provide for operating an engine at all of the modes specified in the present steady-state nonroad test cycles but without the breaks in emission collection required by switching between modes, stabilizing engine operation, and collecting emissions at that next operating mode. Since a ramped modal cycle (RMC) test cycle may more reliably and consistently report engine emissions from particulate trap and other emission control hardware-equipped nonroad engines than the comparable steady-state duty cycle from which it was derived, the Agency is providing the option of using these RMC versions of its steady-state engine duty cycles for nonroad diesel engine certification testing in lieu of the otherwise applicable steady-state cycles. Details on the procedures may be found in chapter 4.2 of the RIA for this rule and at regulations at 40 CFR 1039.505 and Appendix I of part 1039.

The optional RMC duty cycles do not represent a relaxation in stringency of emission testing nor are they an unreasonable increase in the emission test burden of diesel engine manufacturers. Rather, the RMC versions of EPA's steady-state test cycles allow for more consistent and predictable emission testing of emission control system hardware-equipped diesel engines. Eliminating the "downtime" between modes for the emission collection equipment allows sampling of emissions to be done on a composite basis for the whole test as opposed to sampling emissions mode-by-mode. The RMC versions of these tests simply create a negligible transition period 20 seconds long connecting each mode and collects emissions during these brief transitions, as well as collecting emissions during the running of each test's discrete operating modes. The continuous emission sampling allows regeneration events from engine emission control hardware to be captured more reliably and repeatably. By running emission testing without breaks and over the same engine duty schedule for each repetition of a RMC test, regeneration within the engine's emission control hardware should become almost a predictable event. The longer sampling times of RMCs, while creating an identical weighting of each mode's emissions, also help to avoid collecting a minuscule, possibly unreliably measured, amount of sample over the course of any single operating mode. PM emissions, for example, can be collected and measured more precisely under these test conditions as either batch or continuous samples. The opportunities for loss of emissions during sampling and storage due to sample retention by equipment at shut-down between modes or by filter handling and weighing are greatly reduced. As well, running a "steady-state" test on a continuous basis allows cycle performance statistics to be applied to RMC emission tests (see 40 CFR, part 39). Manufacturers are familiar with test cycles run with a set of statistical engine duty cycle performance "targets". Further, their test runs will be subject to less test cell "tuning", modifying control strategies using repeat testing runs to fit the emission test cycle and the dynamometer to operate a particular engine. Finally, statistical targets serve to increase repeatability and reduce variability of engine operating parameters and emission test results on a test-to-test basis.

Transport refrigeration unit (TRU) engines, a specific application of a steady-state operation engine (68 FR 28485, May 23, 2003), will be subject to both steady-state and NTE standards based on any normal operation that these engines would experience in the field. To that end, EPA has adopted a four-mode steady-state test cycle designed specifically for engines used in TRU applications which may be used by the manufacturer in lieu of normal steady-state testing. Commenters to the rule agreed that a TRU test cycle would be more representative of refrigeration unit operation than the nonroad cycles currently available to manufacturers of TRU engines, but some took issue with EPA's usage restrictions in paragraphs (d)(2), (e)(2), and (e)(3) of regulations proposed at 40 CFR part 1039 subpart G. In response, the final rule allows manufacturers to test their engines under a broad definition of intermediate test speed. The definition covers the 60–75% range of engine rpm at the specified test cycle engine load points, as defined in 40 CFR, 89.2. This will enable an engine manufacturer to more closely match the TRU cycle to the operation of their engines in-use. Further, the engine is allowed to exhibit no more than 2% variation in transient operation (speed or torque change) around the four operating modes defined under this test cycle. The provisions to address load set point drift are discussed in detail in the RIA chapter 4.3.2 and in regulations at 40 CFR part 1039 subpart G.

In choosing to certify their engine as a TRU engine, manufacturers will need to state on the engine emission control label that the engine will only be used in a TRU application and records must be kept on the delivery destination(s) for their engines. Manufacturers of these engines may petition EPA at certification for a waiver of the requirement to provide smoke emission

[82] Letter from EMA (Engine Manufacturers Association) to EPA Air Docket A–2001–28, IV–D–402, pp 64.

[83] Memorandum and summary of technical discussions (including Appendix "A" text) in the e-Docket submission, OAR–2003–0012–0028, to EPA's Air Docket.

data for their constant-torque engines. A more detailed discussion of the TRU associated provisions is contained in chapter 4.2 of the RIA. It should be noted that an RMC version of the steady state TRU duty cycle is provided in Table 2 of 40 CFR part 1039 subpart G.

G. Other Test Procedure Issues

This section contains further detail and explanation regarding several related nonroad diesel engine emissions test and measurement provisions. The test procedures are specified in 40 CFR part 1065 and part 1039 subpart F. Part 1065 contains general test procedure requirements and part 1039 contains the provisions that are specific to CI nonroad engines, such as test cycles. The changes described here will not significantly affect the stringency of the standards. While some of the changes being made may appear to increase the stringency of the standards when considered by themselves, others would appear to have the opposite effect. When considered together, however, they will result in more repeatable and less subjective testing that is equivalent to the existing procedures with respect to stringency.

1. Smoke Testing

To control smoke emissions, we are requiring in this final rule that the current smoke standards and procedures will continue to apply to certain engines. We proposed to change these smoke standards and procedures, based on recent developments toward an established international protocol that was designed to allow a straightforward method to test engines in the field (68 FR 28486, May 23, 2003). We have chosen not to adopt the proposed approach, mainly because it is becoming increasingly clear that ongoing development of in-use testing equipment will allow direct measurement of PM emissions in the field. We believe this will provide the best long-term control of both PM emissions. Controlling smoke is in some ways independent of PM, but the interest in developing an in-use smoke test was primarily as a means of providing a secondary indicator of high in-use PM emissions from these engines. Direct PM measurement removes much of the advantage of in-use smoke measurements. Relying on the existing smoke test also addresses concerns raised by manufacturers that the effort to comply with the new smoke requirements would be a large testing and development burden with little air-quality benefit. We believe that aftertreatment-based Tier 4 PM standards will control smoke emissions as well as improved smoke testing standards and procedures. Engines below 19 kilowatts (kW) will generally not have particulate filters, but most of these are constant-speed engines and are therefore not subject to smoke standards, as described below.

We are continuing the established policy of exempting constant-speed engines and single-cylinder engines from smoke standards. We do not believe that constant-speed engines undergo the kind of acceleration or lugging events that occur during this smoke test procedure, so it would not be appropriate for these engines to be subject to smoke standards. We exempt single-cylinder engines for a different reason. These engines, which very often provide power for generator sets and other constant-speed applications, but may in some cases experience accelerations, the nature of single-cylinder engine operation makes it difficult to get a valid smoke emission measurement. Single-cylinder engines generally have discrete puffs of smoke, rather than a stable emission stream for measuring smoke values. We believe it is not appropriate to use such erratic measurements to evaluate an engine's emission performance. As a result, we will not require single-cylinder engines to meet our smoke standards until we find a test method that takes this into account.

Also, as described in the proposed rule, we are exempting from smoke emission standards any engines that are certified to PM emission standards or FELs at or below 0.07 g/kW-hr. We believe any engine that has such low PM emissions will have inherently low smoke emissions. No commenters disagreed with this position.

2. Maximum Test Speed

We are changing how test cycles are specified. As proposed, we are applying the existing definition of maximum test speed in 40 CFR part 1065 to nonroad CI engines. This definition of maximum test speed is the single point on an engine's normalized maximum power versus speed curve that lies farthest away from the zero-power, zero-speed point. This is intended to ensure that the maximum speed of the test is representative of actual engine operating characteristics and is not improperly used to influence the parameters under which their engines are certified. In establishing this definition of maximum test speed, it was our intent to specify the highest speed at which the engine is likely to be operated in use. Under normal circumstances this maximum test speed should be close to the speed at which peak power is achieved. However, in past discussions, some manufacturers have indicated that it is possible for the maximum test speed to be unrepresentative of in-use operation. Since we were aware of this potential during the original development of this definition, we included provisions to address issues such as these. Part 1065 allows EPA to modify test procedures in situations where the specified test procedures would otherwise be unrepresentative of in-use operation. Thus, in cases in which the definition of maximum test speed resulted in an engine speed that was not expected to occur with in-use engines, we would work with the manufacturers to determine the maximum speed that would be expected to occur in-use (see regulations at 40 CFR 1065.10 (c)).

3. Improvements to the Test Procedures

As we proposed, we are making changes to the test procedures to improve the precision of emission measurements. These changes address the potential effect of measurement precision on the feasibility of the standards. It is important to note that these changes are not intended to bias results high or low, but only to improve the precision of the measurements. Based on our experience with these modified test procedures, and our discussions with manufacturers about their experiences, we are confident that these changes will not affect the stringency of the standards. These changes are summarized briefly here. The rationale for the changes are discussed in detail elsewhere. The changes affecting Constant Volume Sampling (CVS) and PM testing are discussed in a memo to the docket (Air Docket A–99–06, IV–B–11), which was originally submitted in support of the recent highway heavy-duty diesel engine rule (66 FR 5001, January 18, 2001).

In general, we are applying the highway heavy-duty engine test procedures to nonroad CI engines in this rulemaking. Many of the specific changes being adopted are to the PM sampling procedures. The PM procedures are the procedures finalized as part of the highway heavy-duty diesel engine rule (66 FR 5001, January 18, 2001). These include changes to the type of PM filters that are used and improvements in how PM filters are weighed before and after emission measurements, including requirements for more precise microbalances.

It is also worth noting that we intend to make additional improvements to the test procedures in a separate rulemaking that will be proposed later this year to incorporate the latest measurement technologies. Many of the improvements being considered were discussed in the previously-mentioned memo to the docket (Air Docket A–99–06, IV–B–11). We recognize the importance of these improvements for use in testing by nonroad diesel engine manufacturers and EPA. However, since we expect that the changes would also apply to many nonroad spark-ignition engine manufacturers, it is appropriate to conduct a separate notice and comment rulemaking for all affected parties. We remain committed to incorporating appropriate additional improvements to the test procedures. We have placed into the docket a draft revised version of part 1065 that represents our current thinking on appropriate testing regulations.

H. Engine Power

Currently, rated power and power rating are undefined, and we are concerned that this makes the applicability of the standards too subjective and confusing. One manufacturer may choose to define rated power as the maximum measured power output, while another may define it as the maximum measured power at a specific engine speed. Using this second approach, an engine's rated power may be somewhat less than the true maximum power output of the engine. Given the importance of engine power in defining which standards an engine must meet and when, we believe that it is critical that a singular power value be determined objectively according to a specific regulatory definition.

To address this, we proposed to add a definition of "maximum engine power" to the regulations. This term was to be used instead of previously undefined terms such as "rated power" or "power rating" to specify the applicability of the standards. The addition of this definition was intended to allow for more objective applicability of the standards. More specifically, we proposed that:

> Maximum engine power means the measured maximum brake power output of an engine. The maximum engine power of an engine configuration is the average maximum engine power of the engines within the configuration. The maximum engine power of an engine family is the highest maximum engine power of the engines within the family.

During the comment period, manufacturers opposed the proposed definition. (We received no other comments on this issue.) The manufacturers correctly pointed out that they cannot know the average actual power of production engines when they certify an engine family, because certification typically occurs before production begins. Therefore the definition of "maximum engine power" being finalized today relies primarily upon the manufacturer's design specifications and the maximum torque curve that the manufacturer expects to represent the actual production engines. This provision is specified in a new section 40 CFR 1039.140. Under this approach the manufacturer would take the torque curve that is projected for an engine configuration, based on the manufacturer's design and production specifications, and convert it into a "nominal power curve" that would relate the maximum power that would be expected to engine speed when a production engine is mapped according our specified mapping procedures. The maximum engine power is being defined as the maximum power point on that nominal power curve.

Manufacturers will be required to report the maximum engine power of each configuration in their applications for certification. As with other engine parameters, manufacturers will be required to ensure that the engines that they produce under the certificate have maximum engine power consistent with those described in their applications. However, since we recognize that variability is a normal part of engine production, we will not require that all production engines have exactly the power specified in the application. Instead, we will only require that the power specified in the application be within the normal range of powers of the production engines. Typically, we would expect the specified power to be within one standard deviation of the mean power of the production engines. If a manufacturer determines that the specified power is outside of the normal range, we may require the manufacturer to change the settings of the engines being produced and/or amend the application for certification. In deciding whether to require such amendment, we would consider the degree to which the specified power differed from the production engines, the normal power variability for those engines, whether the engine used or generated emission credits, and whether the error affected which standards applied to the engine.

The preceding discussion presumes that each manufacturer will develop its production processes to produce the engines described in the application. If a manufacturer were to intentionally produce engines different than those described in the application, we would consider the application to be fraudulent, and could void the certificate *ab initio* for those engines. For example, for engines that use emission credits, this could occur if a manufacturer deliberately biased its production variability so that the engines have higher average power than described in the application. If we voided the certificate for those engines the manufacturer would be subject to large fines and any other appropriate enforcement provisions for each engine.

Finally, in light of some of the comments that we received, it is worth clarifying that the maximum engine power will not be used during engine testing. It is only used to define power categories and calculate ABT emission credits.

I. Auxiliary Emission Control Devices and Defeat Devices

Existing nonroad regulations prohibit the use of a defeat device (see 40 CFR 89.107) in nonroad diesel engines. The defeat device prohibition is intended to ensure that engine manufacturers do not use auxiliary emission control devices (AECD) which sense engine operation in a regulatory test procedure and as a result reduce the emission control effectiveness of that procedure.[84] In today's notice we are supplementing existing nonroad test procedures with a transient engine test cycle and NTE emission standards with associated test requirements. As such, the Agency believes that a clarification of the existing nonroad diesel engine regulations regarding defeat devices is required in light of these additional emission test requirements. The defeat device prohibition makes it clear that AECDs which reduce the effectiveness of the emission control system are defeat devices, unless one of several conditions is met. One of these conditions is that an AECD which operates under conditions "included in the test procedure" is not a defeat device.[85] While the existing defeat device definition does contain the term "test procedure," and therefore should be interpreted as including the supplemental testing requirements, we want to make it clear that both the supplemental transient test cycle and NTE emission test procedures are

[84] Auxiliary emission control device is defined at 40 CFR 89.2 as "any element of design that senses temperature, vehicle speed, engine RPM, transmission gear, or any other parameter for the purpose of activating, modulating, delaying or deactivating the operation of any part of the emission control system."

[85] 40 CFR 89.107(b)(1) states "Defeat device includes any auxiliary emission control device (AECD) that reduces the effectiveness of the emission control system under conditions which may reasonably be expected to be encountered in normal operation and use unless such conditions are included in the test procedure."

included within the defeat device regulations as conditions under which an operational AECD will not be considered a defeat device. Therefore, we are clarifying the defeat device regulations by specifying the appropriate test procedures (*i.e.*, the existing steady-state procedures and the supplemental tests). We are clarifying the engine manufacturers certification reporting requirements with respect to the description of AECDs. Under the previous nonroad engine regulations, manufacturers are required to provide a generalized description of how the emissions control system operates and a "detailed" description of each AECD installed on the engine (see 40 CFR 89.115(d)(2)). This change clarifies what is meant by "detailed."

For engines rated above 750 horsepower, the expanded interpretation of "included in the test cycle" extends only to the NTE because we are not requiring these engine to be tested over the supplemental transient test cycle. Transient emissions control strategies that are substantially included in the NTE will be considered to comply with the defeat device criteria. For instances where transient emissions control strategies are not well represented over the official test requirements, we will rely on the defeat device provisions to ensure appropriate transient off-cycle emissions control. The defeat device provisions restrict the ability of manufacturers to reduce the level of emissions control during transient operation compared to that employed over the steady state cycle. In order to evaluate transient emissions control strategies for compliance with the defeat device provisions, we are requiring manufacturers to submit information which indicates how transient emissions are controlled during normal operation and use. Information that would adequately fulfill this requirement includes but is not limited to:

A. Emissions data gathered with portable emissions measurement systems from in-service engines operating over a broad range of typical transient conditions;

B. Emissions data generated under laboratory conditions representing a broad range of typical transient operation;

C. Transient test cycle results from certified engines rated at or below 750 horsepower which share nearly identical transient emissions control strategies;

D. Base emissions control maps along with an explanation for differences in control between portions of the map substantially included in the steady-state test cycle and that which is predominately associated with transient operation;[86]

E. A comparative analysis of the base emissions control maps from certified engines rated at or below 750 horsepower and those rated over 750 horsepower.

We will use this information to determine the degree to which the design and effectiveness of the transient emissions control system compares to the control demonstrated over the steady-state cycle as well as the transient control used for certified engines at or below 750 horsepower where compliance over the transient cycle is required.

A thorough disclosure of the presence and purpose of AECDs is essential in allowing EPA to evaluate the AECD and determine whether it represents a defeat device. Clearly, any AECD which is not fully identified in the manufacturer's application for certification cannot be appropriately evaluated by EPA and therefore cannot be determined to be acceptable by EPA. Our clarifications to the certification application requirements include additional detail specific to those AECDs which the manufacturer believes are necessary to protect the engine or the equipment in which it is installed against damage or accident ("engine protection" AECDs). While the definition of a defeat device allows as an exception strategies needed to protect the engine and equipment against damage or accident, we intend to continue our policy of closely reviewing the use of this exception. In evaluating whether a reduction in emissions control effectiveness is needed for engine protection, EPA will closely evaluate the actual technology employed on the engine family, as well as the use and availability of other emission control technologies across the industry, taking into consideration how widespread the use is, including its use in similar engines and similar equipment. While we have specified additional information related to engine protection AECDs in the regulations, we reserve the right to request additional information on a case-by-case basis as necessary.

In the last several years, EPA has issued extensive guidance on the disclosure of AECDs for both highway and nonroad diesel engine manufactures. These provisions do not impose any new certification burden on engine manufacturers, rather, it clarifies the existing certification application regulations by specifying what type of information manufacturers must submit regarding AECDs.

Finally, we take this opportunity to emphasize that the information submitted must be specific to each engine family. The practice of describing AECDs in a "common" section, wherein the strategies are described in general for all the manufacturer's engines, is acceptable as long as each engine family's application contains specific references to the AECDs in the common section which clearly indicate which AECDs are present on that engine family, and the application contains specific calibration information for that engine family's AECDs. The regulatory requirements can be found at 40 CFR 89.115(d)(2) in today's notice.

J. Not-To-Exceed Requirements

In today's action we are finalizing not-to-exceed (NTE) emission standards for all new nonroad diesel engines subject to the Tier 4 emissions standards beginning in 2011. These NTE standards and requirements are largely identical to the NTE provisions we proposed, except as noted below.

The NTE standards and test procedures are being finalized to help ensure that nonroad diesel emissions are controlled over the wide range of speed and load combinations commonly experienced in-use. EPA has similar NTE standards for highway heavy-duty diesel engines, compression ignition marine engines, and nonroad spark-ignition engines. The NTE requirements supplement the existing steady-state test as well as the new transient test which is also being finalized today.

The NTE standards and test procedures which we proposed, and which we are finalizing, are derived from similar NTE standards and test procedures which EPA adopted for highway heavy-duty diesel engines. In the proposal, we requested comment on an alternative NTE test procedure approach (see 68 FR 28369, May 23, 2003). As discussed in the proposal, the two NTE approaches would result in the same overall level of emission control, but the implementation of each approach from an in-use measurement and data gathering perspective are quite different. We have decided not to finalize this alternative approach. This decision is based primarily on our belief that nonroad engine manufacturers will more easily transfer the knowledge and experience gained from the highway NTE implementation (which begins in 2007) to the nonroad program if the two programs have similar requirements. For additional discussion regarding our

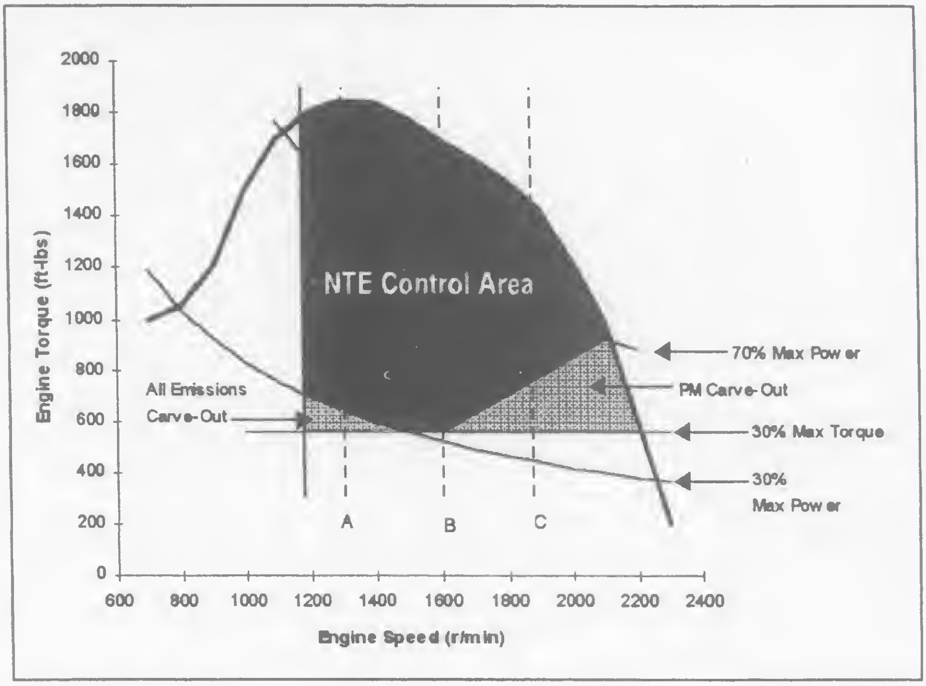
[86] Base emissions control maps describe the modulation of an emissions control parameter as a function of changing engine speed and torque.

decision to not finalize the alternative approach, please see the Summary and Analysis of Comments.

The NTE requirements establish an area (the "NTE zone" or "NTE control area") under the torque curve of an engine where emissions must not exceed a specified value for any of the regulated pollutants.[87] An illustrative NTE zone is shown in Figure III.J–1.

Figure III.J-1: Example NTE Control Area

Note: PM Carve-Out region only applies for engines with a PM standard or FEL greater than or equal to 0.05 g/bhp-hr



The NTE standard applies during any conditions that could reasonably be expected to be seen by that engine in normal operation and use, within certain broad ranges of real ambient conditions. The NTE requirements will help to ensure emission benefits over the full range of in-use operating conditions. The NTE being finalized today for nonroad contains the same basic provisions as the highway NTE. This NTE control area is defined in the same manner as the highway NTE control area, and is therefore a subset of the engine's possible speed and load operating range. The NTE standard applies to emissions sampled during a time duration as small as 30 seconds. The NTE standard requirements for nonroad diesel engines are summarized below and specified in the regulations at 40 CFR 1039.101 and 40 CFR 1039.515. These requirements will take effect as early as 2011, as shown in table III.J–1. The NTE standard applies to engines at the time of certification as well as in use throughout the useful life of the engine.

TABLE III.J–1.—NTE STANDARD IMPLEMENTATION SCHEDULE

Power category	NTE implementation model year [a]
<25 hp	2013
25–75 hp	2013 [b]
75–175 hp	2012
175–750 hp	2011
>750 hp	2011

Notes:

[a] The NTE applies for each power category once Tier 4 standards are implemented, such that all engines in a given power category are required to meet NTE standards.

[b] The NTE standard would apply in 2012 for any engines in the 50–75 hp range which choose not to comply with the proposed 2008 transitional PM standard.

The NTE test procedure can be run in nonroad equipment during field operation or in an emissions testing laboratory using an appropriate dynamometer. The test itself does not involve a specific operating cycle of any specific length; rather, it involves nonroad equipment operation of any type which could reasonably be expected to occur in normal nonroad equipment operation that could occur within the bounds of the NTE control area. The nonroad engine is operated under conditions that may reasonably be expected to be encountered in normal operation and use, including operation under steady-state or transient conditions and under varying ambient conditions. Emissions are averaged over a minimum time of thirty seconds and then compared to the applicable emission standard. The NTE standard applies over a wide range of ambient conditions, including up to an altitude

[87] Torque is a measure of rotational force. The torque curve for an engine is determined by an engine "mapping" procedure specified in the Code of Federal Regulations. The intent of the mapping procedure is to determine the maximum available torque at all engine speeds. The torque curve is merely a graphical representation of the maximum torque across all engine speeds.

of 5,500 feet above-sea level at ambient temperatures as high as 86 deg. F, and at sea-level up to ambient temperatures as high as 100 deg. F. The specific temperature and altitude conditions under which the NTE applies, as well as the methodology for correcting emissions results for temperature and/or humidity, are specified in the regulations.

For new nonroad diesel engines subject to the NTE standards, we will require that manufacturers state in their application for certification that they are able to meet the NTE standards under all conditions that may reasonably be expected to occur in normal equipment operation and use. Manufacturers will have to maintain a detailed description of any testing, engineering analysis, and other information that forms the basis for their statement. We believe that there is a variety of information that a manufacturer could use as a reasonable basis for a statement that engines are expected to meet NTE standards. For example, a reasonable basis could include data from laboratory steady-state and transient test cycle operation, a robust engine emissions map derived from laboratory testing (*e.g.*, an emissions map of similar resolution to the engine's base fuel injection timing map) and technical analysis relying on good engineering judgment which are sufficient, in combination, to project emissions levels under NTE conditions reasonably expected to be encountered in normal operation and use. Data generated from in-use nonroad equipment testing to determine emission levels could, at the manufacturer's option, also be part of this combination. However, a reasonable basis for the manufacturer's statement does not require in-use emissions test data. This statement could reasonably be based solely on laboratory test data, analysis, and other information reasonably sufficient to support a conclusion that the engine will meet the NTE under conditions reasonably expected to be encountered in normal vehicle operation and use. If a manufacturer has relevant in-use nonroad emissions test data, it should be taken into consideration by the manufacturer in developing the basis for its statement.

In addition, as we proposed, we are finalizing a transition period during which a manufacturer could apply for an NTE deficiency for a nonroad diesel engine family. The NTE deficiency provisions would allow the Administrator to accept a nonroad diesel engine as compliant with the NTE standards even though some specific requirements are not fully met. We are finalizing these NTE deficiency provisions because we believe that, despite the best efforts of manufacturers, for the first few model years it is possible some manufacturers may have technical problems that are limited in nature but cannot be remedied in time to meet production schedules. We are not limiting the number of NTE deficiencies a manufacturer can apply for during the first three model years for which the NTE applies. For the fourth through the seventh model year after which the NTE standards are implemented, a manufacturer could apply for no more than three NTE deficiencies per engine family. Within an engine family, NTE deficiencies must be applied for on an engine model or power rating basis; however, the same deficiency when applied to multiple ratings or models counts as a single deficiency within an engine family. No deficiency may be applied for or granted after the seventh model year. The NTE deficiency provision will only be considered for failures to meet the NTE requirements. EPA will not consider an application for a deficiency for failure to meet the FTP or supplemental transient standards.

Similar to the 2007 highway HD rule, we are also finalizing a provision which would allow a manufacturer to exclude defined regions of the NTE engine control zone from NTE compliance if the manufacturer could demonstrate that the engine, when installed in a specified nonroad equipment application(s), is not capable of operating in such regions. We have also finalized a provision which would allow a manufacturer to petition the Agency to limit testing in a defined region of the NTE engine control zone during NTE testing. This optional provision would require the manufacturer to provide the Agency with in-use operation data which the manufacturer could use to define a single, continuous region of the NTE control zone. This single area of the control zone must be specified such that operation within the defined region accounts for 5 percent or less of the total in-use operation of the engine, based on the supplied data. Further, to protect against "gaming" by manufacturers, the defined region must generally be elliptical or rectangular in shape, and share a boundary with the NTE control zone. If approved by EPA, the regulations then disallow testing with sampling periods in which operation within the defined region constitutes more than 5.0 percent of the time-weighted operation within the sampling period.

The NTE numerical standard is a function of FTP emission standards contained in today's final rule, which standards are described in section II. As with the NTE standards we have established for the 2007 highway rule, the nonroad NTE standard is determined as a multiple of the engine families' underlying FTP emission standard. In addition, as with the 2007 highway standard, the multiple is either 1.25 or 1.5, depending on the emission pollutant type and the value of the FTP standard (or the engine families' FEL). These multipliers are based on EPA's assessment of the technological feasibility of the NTE standard, and our assessment that as the underlying FTP standard becomes more stringent, the NTE multiplier should increase (from 1.25 to 1.5). The FTP standard or FEL thresholds for the NTE standard's 1.25x multiplier and the 1.5x multiplier are specified for each regulated emission in table III.J–2.

TABLE III.J–2.—THRESHOLDS FOR APPLYING NTE STANDARD OF 1.25X FTP STANDARD VS. 1.5X FTP STANDARD

Emission	Apply 1.25x NTE when . . .	Apply 1.5x when . . .
NO_X	NO_X std or FEL ≥ 1.9 g/bhp-hr	NO_X std or FEL < 1.9 g/bhp-hr
NMHC	NO_X std or FEL ≥ 1.9 g/bhp-hr	NO_X std or FEL < 1.9 g/bhp-hr
NO_X+NMHC	NMHC+NO_X std or FEL ≥ 2.0 g/bhp-hr	NMHC+NO_X std or FEL < 2.0 g/bhp-hr
PM	PM std or FEL ≥ 0.05 g/bhp-hr	PM std or FEL < 0.05 g/bhp-hr
CO	All stds or FELs	No stds or FELs

For example, beginning in 2011, the NTE standard for engines meeting a FTP PM standard of 0.01 g/bhp-hr and a FTP NO_X standard of 0.30 g/bhp-hr would be 0.02 g/bhp-hr PM and 0.45 g/bhp-hr NO_X. In the NPRM, we proposed a NO_X

threshold value of 1.5 g/bhp-hr as the value at which the NTE multiplier would switch from 1.5 to 1.25.

We proposed this NO_X emission threshold level (1.5 g/bhp-hr) primarily because it is the same value as we finalized for the highway NTE. As shown in table III.J–2, we have finalized a threshold value of 1.9 g/bhp-hr NO_X for nonroad engines. We have finalized this higher NO_X threshold based on the differences in the emission performance of NO_X control technologies between highway and nonroad diesel engines. Specifically, nonroad diesel NO_X standards have traditionally been higher than the equivalent highway NO_X standard due primarily to the effectiveness of charge-air-cooling and the lack of ram-air for nonroad applications. For example, the nonroad Tier 3 NMHC+NO_X standards are higher than the 2004 heavy-duty highway standards (*e.g.*, 3.0 g/bhp-hr vs. 2.5 g/bhp-hr), and the Tier 4 NO_X standard is higher than the 2007 heavy-duty highway standard (*e.g.*, 0.3 g/bhp-hr vs. 0.2 g/bhp-hr). We expect that the nonroad Tier 3 standard for engines above 100 hp will require NO_X levels of approximately 2.5 g/bhp-hr and we expect that for the 2004 highway heavy-duty standards, NO_X levels are approximately 2 g/bhp-hr. In both cases, these emission levels are the building blocks for the next set of EPA standards (*e.g.*, Tier 4 for nonroad and 2007 for highway). Because the nonroad Tier 3 NO_X emission levels are expected to be approximately 25 percent greater than the 2004 highway level (2.5 vs 2), we believe that the NTE NO_X multiplier threshold for nonroad should be 25 percent greater for nonroad as compared to highway. For these reasons, we have finalized a NO_X multiplier threshold of 1.9 g/bhp-hr, which is 25 percent greater than the highway multiplier threshold.

In addition, as proposed, we are finalizing a number of specific engine operating conditions during which the nonroad NTE standard would not apply. The exact criteria for these conditions are defined in the regulations, but in summary: the NTE does not apply during engine start-up conditions; the NTE does not apply during very cold engine intake air temperatures for EGR-equipped engines during which the engine may require an engine protection strategy; and, finally, for engines equipped with NO_X and/or NMHC aftertreatment (such as a NO_X adsorber), the NTE does not apply during warm-up conditions for the exhaust emission control device. Finally, while we did not propose this, we are finalizing the NTE PM carve-out provisions for engines which will not require PM filters. The PM only carve-out is a sub-region of the NTE zone in which the NTE PM standard does not apply. Figure III.J–1 contains an illustration of the PM carve-out. This is a region of high engine speed and low engine torque during which engine-out PM emissions are difficult to control to levels below the PM NTE standard. The dimensions of the PM carve-out are specified in the regulations. For engines equipped with a PM filter, compliance with the PM NTE standard in this region is achievable due to the highly efficient PM reduction capabilities of the CDPF technology. However, for engines in the under 25 hp category, for which we have established Tier 4 emission standards that do not require the use of a PM filter, PM control in this sub-region of the NTE zone with conventional PM reduction technologies may not be achievable. Therefore, as we allowed with highway heavy-duty engines certifying to the 0.1 g/bhp-hr standard, we have created a PM carve-out for nonroad engines that use in-cylinder PM control technologies. Specifically, the PM carve-out applies to engines meeting a PM standard or FEL greater than or equal to 0.05 g/bhp-hr.

K. Investigating and Reporting Emission-Related Defects

In 40 CFR part 1068, subpart F, we are adopting defect reporting requirements that obligate manufacturers to tell us when they learn that emission-control systems are defective and to conduct investigations under certain circumstances to determine if an emission-related defect is present. Under these defect-reporting requirements, manufacturers must track available warranty claims and any other available information from dealers, hotlines, diagnostic reports, or field-service personnel to identify possible defects. If the number of possible defects exceeds certain thresholds, they must investigate future warranty claims and other information to establish whether these are actual defects.

We believe the investigation requirement in this rule will allow both EPA and the engine manufacturers to fully understand the significance of any unusually high rates of warranty claims for systems or parts that may have an impact on emissions. In the past, defect reports were submitted based on a very low threshold with the same threshold applicable to all size engine families and with little information about the full extent of the problem. The new approach should result in fewer overall defect reports being submitted by manufacturers than would otherwise be required under the old defect-reporting requirements because the number of defects triggering the submission requirement rises with the engine family size. The new approach may trigger some additional reports for small-volume families, but the percentage-based approach will ensure that investigations and reports correspond to issues that are likely to be significant.

Part 1068, subpart F, is intended to require manufacturers to use information we would expect them to keep in the normal course of business. We believe in most cases manufacturers will not be required to institute new programs or activities to monitor product quality or performance. A manufacturer that does not keep warranty or replacement part information may ask for our approval to use an alternate defect-reporting methodology that is at least as effective in identifying and tracking possible emission-related defects as the requirements of 40 CFR 1068.501. Thus manufacturers will have the flexibility to develop defect tracking and reporting programs that work better for their standard business practices. However, until we approve such a request, the thresholds and procedures of subpart F continue to apply.

Manufacturers may also ask for our approval to use an alternate defect-reporting methodology when the requirements of 40 CFR 1068.501 can be demonstrated to be highly impractical or unduly burdensome. In such cases, we will generally allow alternate methodologies that are at least as effective in identifying, correcting, and informing EPA of possible emission-related defects as the requirements of 40 CFR 1068.501. We expect this flexibility to be useful in special circumstances such as when new models of very large engines are introduced for the first time. In this situation, it may be appropriate to allow an alternate defect reporting method because the high cost of these engines often makes it impractical to build and test large numbers of prototype engines. The initial production of these engines can have similar defect rates to the high levels often associated with prototype engines. While we are concerned about such defects and want to be kept informed about them, it is not clear that our basic program would be the best way to address these defects. In such cases, we believe it may be more appropriate for manufacturers to propose an alternative approach that consolidates reports on a regular interval, such as quarterly, and identifies obvious early-life defects without a formal tracking process. In general, we would encourage manufacturers to propose an alternate approach to ensure that these defects are properly addressed while minimizing the associated burden.

Issues related to parts shipments received the most attention from commenters who pointed out that the proposed requirement to track shipments of all emission-related components was overly burdensome and not likely to reveal useful information. We have concluded that it is not appropriate to use parts shipments as a quantitative indicator to evaluate whether manufacturers exceed the threshold that would trigger an investigation. We generally agree with manufacturers concerns that parts-shipments data would be too difficult to evaluate, for example, because parts are often shipped for stocking purposes, parts are installed in compliant and noncompliant products (such as exported engines), and part shipments are generally not identifiable by model year. The final rule therefore requires manufacturers to pursue a defect investigation if the number of shipped parts is higher than the manufacturer would expect based on historical shipment levels, specifications for scheduled maintenance, or other factors.

We have modified the proposed thresholds to address concerns that manufacturers would be required to investigate and report defects too frequently. For engines under 750 hp, we are adopting investigation thresholds of 10 percent of total production or 50 engines, whichever is greater, for any single engine family in one model year. Similarly, we are adopting defect-reporting thresholds of 2 percent of total production or 20 engines, whichever is greater. For engines over 750 hp, the same percentage thresholds apply, but we are extending the percentage values down to smaller engine families to reflect their disproportionate contribution to total emissions. For these engines, the absolute thresholds are 25 engines for investigations and 10 or 15 engines for defects (see table III.K–1). We believe these thresholds adequately balance the desire to document emission-related defects without imposing an unreasonable reporting burden. Also, we believe this approach to adopting thresholds adequately addresses reporting requirements for aftertreatment and non-aftertreatment components.

TABLE III.K–1.—INVESTIGATION AND DEFECT-REPORTING THRESHOLDS FOR VARYING SIZES OF ENGINE FAMILIES[1]

Engine size	Investigation threshold	Defect-reporting threshold
≤750 hp	less than 500: 50	less than 1,000: 20
	500–50,000: 10%	1,000–50,000: 2%
	50,000+: 5,000	50,000+: 1,000
>750 hp		less than 150: 10
	less than 250: 25	150–750: 15
	250+: 10%	750+: 2%

Notes:
[1] For varying sizes of engine families, based on sales per family in a given model year.

EMA also expressed concern about the existing regulatory language in 40 CFR 1068.501(b)(3), which states that manufacturers must "consider defects that occur within the useful life period, or within five years after the end of the model year, whichever is longer." However, this provision has no effect on the diesel engines subject to the Tier 4 standards being adopted today, since they all have useful lives of at least five years. We recognize that this issue may be relevant to engine categories that do not have five-year useful lives, such as small SI engines, and will consider these concerns in our future regulation of such engines.

When manufacturers start an investigation, they must consider any available information that would help them evaluate whether any of the possible defects that contributed to triggering the investigation threshold would lead them to conclude that these were actual defects. Otherwise, manufacturers are expected to look prospectively at any possible defects and attempt to determine whether these are actual defects. Also, during an investigation, manufacturers should use appropriate statistical methods to project defect rates if they are unable to collect information to evaluate possible defects, taking steps as necessary to prevent bias in sampled data (or making adjusted calculations to take into account any bias that may remain). For example, if 75 percent of the components replaced under warranty are available for evaluation, it would be appropriate to extrapolate known information on failure rates to the components that are unavailable for evaluation.

The second threshold in 40 CFR 1068.501 specifies when a manufacturer must report that there is an emission-related defect. This threshold involves a smaller number of engines because each possible occurrence has been screened to confirm that it is in fact an emission-related defect. In counting engines to compare with the defect-reporting threshold, the manufacturer generally considers a single engine family and model year. Where information cannot be differentiated by engine family and model year, the manufacturer must use good engineering judgment to evaluate whether the information leads to a conclusion that the number of defects exceeds the applicable thresholds. However, when a defect report is required, the manufacturer must report all occurrences of the same defect in all engine families and all model years.

If the number of engines with a specific defect is found to be less than the threshold for submitting a defect report, but information such as warranty data later indicates that there may be additional defective engines, all the information must be considered in determining whether the threshold for submitting a defect report has been met. If a manufacturer has actual knowledge from any source that the threshold for submitting a defect report has been met, a defect report must be submitted even if the trigger for investigating has not yet been met. For example, if manufacturers receive from their dealers, technical staff or other field personnel information showing conclusively that there is a recurring emission-related defect, they must submit a defect report.

If manufacturers trigger the threshold to start an investigation, they must promptly and thoroughly investigate whether their parts are defective, collecting specific information to prepare a report describing their conclusions. Manufacturers must send the report if an investigation concludes that the number of actual defects did not exceed reporting thresholds. Manufacturers must also send these as status reports twice annually during an investigation. After investigating for several months, or perhaps a couple years, it may become clear that the problems that triggered the investigation will never show enough actual defects to trigger a defect report. In this case, the manufacturer would send us a report justifying this conclusion.

In general, we believe this updated approach to defect reporting will decrease the number of defect reports submitted by manufacturers overall while significantly improving their quality and their value to both EPA and the manufacturer.

Note that misbuilds are a special type of emission-related defect. An engine that is not built consistent with its application for certification violates the prohibited act of introducing into commerce engines that are not covered by a certificate of conformity.

L. Compliance With the Phase-In Provisions

In section II we described the NO_X and NMHC standards phase-in schedule, which is intended to allow engine manufacturers to phase-in their new advanced technology engines, while they phase-out existing engines. This phase-in requirement is based on percentages of a manufacturer's production for the U.S. market. We recognize, however, that manufacturers need to plan for compliance well in advance of the start of production, and that actual production volumes for any one model year may differ from their projections. On the other hand, we believe that it would be inappropriate and infeasible to base compliance solely on a manufacturer's projections. That could encourage manufacturers to overestimate their production of complying phase-in engines, and could result in significantly lower emission benefits during the phase-in. In response to these concerns, we proposed to initially only require nonroad diesel manufacturers to project compliance with the phase-in based on their projected production volumes, provided that they made up any deficits (in terms of percent of production) the following year. We received no comments on this issue and are finalizing it as proposed.

Because we expect that a manufacturer making a good-faith projection of sales would not be very far off of the actual production volumes, we are limiting the size of the deficit that would be allowed, as in the highway program. In all cases, the manufacturer would be required to produce at least 25% of its production in each phase-in power category as "phase-in" engines (meeting the NO_X and NMHC standards or demonstrating compliance through use of ABT credits) in the phase-in years (after factoring in any adjustments for early introduction engine credits; see section III.M). This minimum required production level would be 20% for the 75–175 hp category if a manufacturer exercises the option to comply with a reduced phase-in schedule in lieu of using banked Tier 2 ABT credits, as discussed in section III.A.1.b. Another important restriction is that manufacturers would not be allowed to have a deficit in the year immediately preceding the completion of the phase-in to 100%. This would help ensure that manufacturers are able to make up the deficit. Since they could not produce more than 100% low-NO_X engines after the final phase-in year, it would not be possible to make up a deficit from this year. These provisions are identical to those adopted in the highway HDDE program.

We are also finalizing the proposed "split family" allowance for the phase-in years. This provision, which is similar to a provision of the highway program, allows manufacturers to certify engine families to both the phase-in and phase-out standards. Manufacturers choosing this option must assign at the end of the model year specific numbers of engines to the phase-in and phase-out categories. All engines in the family must be labeled with the same NO_X and PM FELs, which apply for all compliance testing, and must meet all other requirements that apply to phase-in engines. Engines assigned to the phase-out category may generate emission credits relative to the phase-out standards.

M. Incentive Program for Early or Very Low Emission Engines

We believe that it is appropriate and beneficial to provide voluntary incentives for manufacturers to introduce engines emitting at very low levels early. Such inducements may help pave the way for greater and/or more cost effective emission reductions from future engines and vehicles. To encourage early introduction of low-emission engines, the proposal contained provisions to allow engine manufacturers to benefit from producing engines certified to the final (aftertreatment-based) Tier 4 standards prior to the 2011 model year, by being allowed to make fewer engines certified to these standards once the Tier 4 program takes effect, a concept that we are terming "engine offsets" to avoid confusion with ABT program credits. The number of offsets that could be generated would depend on the degree to which the engines are able to meet, or perform better than, the final Tier 4 standards. Commenters generally supported this approach, as long EPA ensures that compliance requirements for these engines are enforced.

However, one equipment manufacturer submitted comments suggesting that we should adopt a program that would provide incentives for equipment manufacturers to use the early Tier 4 engines in their equipment. For an early low-emission engine program to be successful, we agree that it is important to provide incentives to both the engine manufacturer and the equipment manufacturer, who may incur added cost to install and market the advanced engine in the equipment. As was pointed out in comments, the proposed program did not provide clear incentives to equipment manufacturers to use the (presumably more expensive) early low-emission engines. Therefore, we are adding such provisions. Section III.B.2.e describes these early Tier 4 engine incentive provisions under which equipment manufacturers can earn increased allowance flexibilities. Under those provisions, the engine manufacturer's incentive to produce the low-emitting engines will come from customers' demand for them, and from the fact that the engine manufacturer can earn ABT program credits for these engines in the same way as without these incentive provisions. If the equipment manufacturer does not wish to earn the increased allowance flexibilities, then the engine manufacturer would be allowed to use the provisions of the incentive program for early low-emission engines described below in this subsection, though to do so would require the forfeiture of any ABT credits earned by the subject engines, essentially to avoid double counting, as explained below. This engine manufacturer incentive program is being adopted as proposed, except for engines above 750 hp, for which the proposed program requires some adjustment to account for the approach we are taking to final standards.

As discussed in section II.A.4, the final rule does not phase in standards for engines above 750 hp as proposed, and instead adopts application-specific standards in 2011 and 2015. The 2011 standards are not based on advanced aftertreatment except for NO_X on engines above 1200 hp used in generator sets. To avoid overcomplication of the incentive program, which might discourage its use, we are not separating over and under 1200 hp generator set engines into separate groups for these provisions. Instead, any of these engines that meet the 2015 standards before 2015 can earn offsets. We are, however, separating the generator set engines and non-generator set engines above 750 hp into separate groups, because we are deferring setting a NO_X standard for the latter that is based on use of advanced aftertreatment technology.

Table III.M–1 summarizes the requirements and available offsets for engine manufacturers in this program. As the purpose of the incentive is to encourage the introduction of clean technology engines earlier than required, we require that the emission standard levels actually be met, and met early, by qualifying engines to earn the early introduction offsets. The regulations specify that the standards must be met without the use of ABT credits and actual production of the engines must begin by September 1 preceding the first model year when the standards would otherwise be applicable. Also, to avoid double-counting, as explained in the proposal, the early engines can earn either the engine offsets or the ABT emission credit, but not both. Note that this is different than the approach taken in the early Tier 4 engine incentive program for equipment manufacturers described in section III.B.2.e, where incentives for both the engine manufacturer (ABT credits) and the equipment manufacturer (allowance flexibilities) are needed to ensure successful early introduction of clean engines. Because 15 ppm sulfur diesel fuel will be available on a widespread basis in time for 2007 (due to the requirements for on-highway heavy-duty engines), we are allowing engine manufacturers to begin certifying engines to the very low emission levels required to be eligible for this incentive program, beginning with the 2007 model year.

TABLE III.M–1.—PROGRAM FOR EARLY INTRODUCTION OF CLEAN ENGINES

Category	Engine group	Must meet [a]	Per-engine offset
Early	25–75 hp	0.02 g/bhp-hr PM	1.5-to-1
PM-only [b]	75–750 hp	0.01 g/bhp-hr PM	PM-only
	25–75 hp	0.02/3.5 g/bhp-hr PM/NMHC+NO_X.	
	75–750 hp	0.01/0.30/0.14 g/bhp-hr PM/NO_X/NMHC.	
	>750 hp generator set	0.02/0.50/0.14 g/bhp-hr PM/NO_X/NMHC	1.5–to–1
Early Engine [b]	>750 hp non-generator set	0.03/2.6/0.14 g/bhp-hr PM/NO_X/NMHC.	
Low NO_X Engine	>25 hp	as above for Early Engine, except must meet 0.15 g/bhp-hr NO_X standard.	2–to–1

Notes:
[a] All engines must also meet the Tier 4 crankcase emissions requirements. Engines must certify using all test and other requirements (such as NRTC and NTE) otherwise required for final Tier 4 standards.
[b] Offsets must be earned prior to the start of phase-in requirements in applicable engine groups (prior to 2013 for 25–75 hp engines, prior to 2012 for 75–175 hp engines, prior to 2011 for 175–750 hp engines, prior to 2015 for >750 hp engines).

For any engines being certified under this program before the 2011 model year using 15 ppm sulfur certification fuel, the manufacturer would have to meet the requirements described in section III.D, including demonstrating that the engine would indeed be fueled with 15 ppm sulfur fuel in the field. We expect this would occur through selling such engines into fleet applications, such as municipal maintenance fleets, large construction company fleets, or any such well-managed centrally-fueled fleet. While obtaining a reliable supply of 15 ppm maximum sulfur diesel fuel prior to the 2011 model year will be possible, it will require some effort by nonroad diesel machine operators. We therefore believe it is necessary and appropriate to provide a greater incentive for early introduction of clean diesel technology. Thus, as proposed, we would count one early engine (that is, an engine meeting the final Tier 4 standards) as offsetting 1.5 engines later. This means that fewer clean diesel engines than otherwise required may enter the market in later years, but, more importantly, it means that emission reductions would be realized earlier than under our base program. We believe that providing incentives for early emission reductions is a worthwhile goal for this program, because improving air quality is an urgent need in many parts of the country as explained in section I, and because the early learning opportunity with new technologies can help to ensure a smooth transition to Tier 4 standards.

We are providing this early introduction offset for engines over 25 hp that meet all of today's Tier 4 emissions standards (NO_X, PM, and NMHC) in the applicable engine category. We are also providing this early introduction offset to engines that pull ahead compliance with only the PM standard. However, a PM-only early engine would offset only the PM standard for an offset-using engine. For engines in power categories with a percentage phase-in, this would correspond (during the phase-in years) to offset use for "phase-out" engines (those required to meet the new Tier 4 standard for PM but not for NO_X or NMHC). Engines using the PM-only offset would be subject to the other applicable Tier 4 emission standards, including applicable transient and NTE standards (see Section III.F) and crankcase requirements. The applicable PM standard and requirements for these PM-only offset-using engines would be those of Tier 3 (Tier 2 for 25–50 hp engines). PM-only offsets would not offset engines required to meet other Tier 4 standards such as the phase-in NO_X and NMHC standards (since there is no reason for PM offsets to offset emissions of other pollutants). Tier 4 engines between 25 and 75 hp certified to the 2008 PM standard would not participate in this program, nor would engines below 25 hp, because they do not have advanced aftertreatment-based standards.

An important aspect of the early incentive provision is that it must be done on an engine count basis. That is, a diesel engine meeting new standards early would count as 1.5 such diesel engines later. This contrasts with a provision done on an engine percentage basis which would count one percent of diesel engines early as 1.5 percent of diesel engines later. Basing the incentive on an engine count alleviates any possible influence of fluctuations in engine sales in different model years.

Another important aspect of this program is that it is limited to engines sold prior to the 2013 model year for engines between 25 and 75 hp, prior to the 2012 model year for engines between 75 and 175 hp, and prior to the 2011 model year for engines between 175 and 750 hp. In other words, as in the highway program, nonroad diesel engines sold during the transitional "phase-in" model years would not be considered "early" introduction engines and would therefore be ineligible to generate early introduction offsets. However, such engines and vehicles would still be able to generate ABT credits. Because the engines over 750 hp engines have no percent-of-production phase-in provisions, we are allowing offsets for early engines in any model year prior to 2015. For the same reason, there is no PM-only offset for these engines. As with the phase-in itself, and for the same reasons, an early introduction engine could only be used to offset requirements for engines in the same engine group (25–75 hp, 75–175 hp, 175–750 hp, >750 hp generator sets, and >750 hp non-generator sets) as the offset-generating engine.

As a further incentive to introduce clean engines and vehicles early, we are also adopting the proposed provision that gives engine manufacturers an early introduction offset equal to two engines during or after the phase-in years for engines with NO_X levels well below the final Tier 4 NO_X standard. This incentive applies for diesel engines achieving a 0.15 g/bhp-hr NO_X standard level (one-half of the aftertreatment-based standard for most engines) while also meeting the NMHC and PM standards. Due to the extremely low emission levels to which these engines and vehicles would need to certify, we believe that the double engine count offset is appropriate.

In the NPRM we asked for comment on whether or not we should extend the existing Blue Sky program that encourages the early introduction of engines with emission levels (as measured on a transient test) about 40% lower than the Tier 2 standards levels. See 68 FR at 28483. We received comments both for and against doing so, but no commenter provided substantive arguments or information. Given the very low emissions levels being adopted in Tier 4, we have decided not to extend the existing Blue Sky Series program, because it does not encourage engines emitting at such low emission levels.

N. Labeling and Notification Requirements

As explained in section II, the emissions standards will make it necessary for manufacturers to employ exhaust emission control devices that require very low-sulfur fuel (less than 15 ppm) to ensure proper operation. This action restricts the sulfur content of diesel fuel used in these engines. However, the 2008 emissions standards would be achievable with less sensitive technologies and thus it could be appropriate for those engines to use diesel fuel with up to 500 ppm sulfur. There could be situations in which vehicles requiring either 15 ppm fuel or 500 ppm may be accidentally or purposely misfueled with higher-sulfur fuel. Any of these misfueling events could seriously degrade the emission performance of sulfur-sensitive exhaust emission control devices, or perhaps destroy their functionality altogether.

In the highway rule, we adopted a requirement that heavy-duty vehicle manufacturers notify each purchaser that the vehicle must be fueled only with the applicable low-sulfur diesel fuel. We also required that diesel vehicles be equipped by the manufacturer with labels near the refueling inlet to indicate that low sulfur fuel is required. We are adopting similar requirements here.[88] Specifically, manufacturers will be required to notify each purchaser that the nonroad engine must be fueled only with the applicable low-sulfur diesel fuel, and ensure that the equipment is labeled near the refueling inlet to indicate that low sulfur fuel is required. We believe that these measures would help owners find and use the correct fuel and would be sufficient to address misfueling concerns. Thus, more costly provisions, such as fuel inlet restrictors, should not be necessary.

In general, beginning in model year 2011, nonroad engines will be required to use the Ultra Low Sulfur diesel fuel (with less than 15 ppm sulfur). Thus, the default label will state "ULTRA LOW SULFUR FUEL ONLY." The labeling requirements for earlier model year Tier 4 engines are specified in § 1039.104(e). Some new labeling requirements for earlier model year Tier 3 engines are specified in 40 CFR 89.330(e). These requirements for earlier years generally require that engines and equipment be labeled consistent with the sulfur of the test fuel used for their certification. So where the engine is certified using Low Sulfur diesel fuel (with less than 500 ppm sulfur), the required label will state "LOW SULFUR FUEL ONLY." See section III.D and the regulatory text for the other specific requirements related to labeling the earlier model years.

O. General Compliance

1. Good Engineering Judgment

The process of testing engines and preparing an application for certification requires the manufacturer to make a variety of judgments. This includes, for example, selecting test engines, operating engines between tests, and developing deterioration factors. EPA has the authority to evaluate whether a manufacturer's use of engineering judgment is reasonable. The regulations describe the methodology we use to address any concerns related to how manufacturers use good engineering judgment in cases where the manufacturer has such discretion (see 40 CFR 1068.5). If we find a problem with a manufacturer's use of engineering judgment, we will take into account the degree to which any error in judgment was deliberate or in bad faith. If manufacturers object to a decision we make under this provisions, they are entitled to a hearing. This subpart is consistent with provisions already adopted for light-duty highway vehicles, marine diesel engines, industrial spark-ignition engines, and recreational vehicles.

2. Replacement Engines

In the proposal we included a provision allowing manufacturers to sell a new, noncompliant engine intended to replace an engine that fails in service. The proposed language closely mirrored the existing provisions in 40 CFR 89.1003(b)(7), except that it specified that manufacturers could produce new, noncompliant replacement engines if no engine from any manufacturer were available with the appropriate physical or performance characteristics. Manufacturers objected to this provision and requested that the final regulations follow the language in 40 CFR part 89, in which the manufacturer of the new engine confirm that no appropriate engine is available from its product line (or that of the manufacturer of the original engine, if that were a different company). We agree that the language from 40 CFR part 89 is appropriate, but we note two things to address remaining concerns that manufacturers could potentially use the replacement-engine provisions to produce large numbers of noncompliant products. First, we are including a specific statement in the regulations that manufacturers may not use the replacement-engine exemption to circumvent the regulations. Second, we plan to use the data-collection provision under 40 CFR 1068.205(d) to ask manufacturers to report the number of engines they sell under the replacement-engine exemption. Rather than adopting a specific data-reporting requirement, we believe this more flexible approach is most appropriate to allow us to get information to evaluate how manufacturers are using the exemption without imposing reporting requirements that may involve more or less information than is actually needed.

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[88] We also required that highway vehicles be labeled on the dashboard. Given the type of equipment using nonroad CI engines, we are not adopting any dashboard requirement here.

3. Warranty

We are modifying 40 CFR 1068.115 regarding engine manufacturers' warranty obligations by removing paragraph (b). This paragraph addresses specific circumstances under which manufacturers may not deny emission-related warranty claims, while paragraph (a) of this section addresses the circumstances under which manufacturers may deny such claims. As described in our Summary and Analysis of Comments related to our November 8, 2002 final rule (67 FR 68242), we intended to adopt 40 CFR1068.115 without this paragraph. We wanted to remove paragraph (b) because we agreed with a comment pointing out that publishing both paragraphs leaves ambiguous which provision applies if a situation applies that is not on either list. Since neither list can be comprehensive, we believe the provisions in paragraph (a) describing when manufacturers may deny warranty claims appropriately addresses the issue. As a result, paragraph (b) was inadvertently adopted as part of the November 2002 final rule.

4. Separate Catalyst Shipment

We are adopting provisions that will allow engine manufacturers to ship engines to equipment manufacturers where the engine manufacturer had not yet installed the aftertreatment or otherwise included it as part of the engine shipment. This allows the engine manufacturer to ship the engine without the aftertreatment; for example, in cases where it would be impractical to install aftertreatment devices on the engine before shipment or even ship products with the aftertreatment devices uninstalled along with the engine; or where shipping it already installed would require it to be disassembled and reinstalled when the engine was placed in the equipment. Today's final rule requires that the components be included in the price of the engine and that the engine manufacturer provide sufficiently detailed and clear instructions so that the equipment manufacturer can readily install the engine and its ancillary components in a configuration covered under the certificate of conformity held by the engine manufacturer. We are also requiring that the engine manufacturer have a contractual agreement obligating the equipment manufacturer to complete the final assembly into a certified configuration. The engine manufacturer must ship any components directly to the equipment manufacturer or arrange for their shipment from a component supplier. The engine manufacturer must tag the engines and keep records. The engine manufacturer must obtain annual affidavits from each equipment manufacturer as to the parts and part numbers that the equipment manufacturer installed on each engine and must conduct a limited number of audits of equipment manufacturers' facilities, procedures, and production records to monitor adherence to the instructions it provided. Where an equipment manufacturer is located outside of the U.S., the audits may be conducted at U.S. port of distribution facilities.

The rule also contains various provisions establishing responsibility for proper installation. Where the engines are not in a certified configuration when installed in nonroad equipment because the equipment manufacturer used improper emission-control devices or failed to install the shipped parts or failed to install the devices correctly, then both the engine manufacturer and the installer have responsibility. For the engine maker, the exemption is void for those engines that are not in their certified configuration after installation. We may also suspend or revoke the exemption for future engines where appropriate, or void the exemption for the entire engine family. The installer is also liable. We may find the equipment manufacturer to be in violation of the tampering prohibitions at 40 CFR 1068.101(b)(1) for the improper installation, which could subject it to substantial civil penalties. In any event, the engine manufacturer remains liable for the in-use compliance of the engine as installed. For example, it has responsibility for the emission-related warranty, including for the aftertreatment, and is responsible for any potential recall liability. However, if noncompliance of the in-use engines stems from improper installation of the aftertreatment, then the tampering that occurred by the installer may remove recall liability. Where the engine manufacturer had complied with the regulations and the failure was solely due to the equipment manufacturer's actions, we would not be inclined to revoke or suspend the exemption or to void the exemption for the entire engine family. We may deny the exemption for future model years if the engine manufacturer does not take action to address the factors causing the nonconformity. On the other hand, if the manufacturer failed to comply, had shipped improper parts, had provided instructions that led to improperly installed parts, or had otherwise contributed to the installation of engines in an uncertified configuration, we might suspend, revoke, or void the exemption for the engine family. In this case, the engine manufacturer would be subject to substantial civil penalties.

P. Other Issues

We are also making other minor changes to the compliance program. These changes are summarized in table III.Q–1 below. For more information about these changes, you should read the NPRM and Summary and Analysis of Comments for this rulemaking. We believe that these changes are straightforward and noncontroversial.

TABLE III.Q–1.—REGULATORY CHANGES

Issue	Regulatory provision
Applicability to alcohol-fueled engines	§§ 1039.101, 1039.107.
Prohibited controls	§ 1039.115.
Emission-related maintenance instructions	§ 1039.125.
Engine installation instructions	§ 1039.130.
Engines labels	§§ 1039.20, 1039.135, 1068.320.
Engine family definition	§ 1039.230.
Test engine selection	§ 1039.235.
Deterioration factors	§ 1039.240.
Engines that use noncommercial fuels	§ 1039.615.
Use of good engineering judgment	§ 1068.5.
Separate shipment of aftertreatment	§ 1068.260.
Exemptions	40 CFR 1068 Subpart C.
Importing engines	40 CFR 1068 Subpart D.

TABLE III.Q–1.—REGULATORY CHANGES—Continued

Issue	Regulatory provision
Hearings	40 CFR 1068 Subpart G.

Q. Highway Engines

We are changing the diesel engine/vehicle labeling requirements in 40 CFR 86.007–35 to be consistent with the new pump labels. This change corrects a mistake in the proposal that would have resulted in confusion for highway vehicle operators. (We received no comment on this issue.)

R. Changes That Affect Other Engine Categories

We are making some minor changes to the regulations in 40 CFR parts 1048 and 1051 for nonroad spark-ignition engines over 19 kW and recreational vehicles, respectively. We are also changing several additional provisions in 40 CFR parts 1065 and 1068, which define test procedures and compliance provisions for these same categories of engines. See the regulatory text for the specific changes. The proposed rule included most of these changes. To the extent there were comments on any of these changes, those issues are addressed elsewhere in this document or in the Summary and Analysis of Comments.

• In 40 CFR 1048.125 and 40 CFR 1051.125, we are correcting the provisions related to critical emission-related maintenance to allow manufacturers to do maintenance during service accumulation for durability testing, as long as their maintenance steps meet the specified criteria ensuring that in-use engines will undergo those maintenance procedures.

• In 40 CFR 1068.27, we clarify that manufacturers must make available a reasonable number of production-line engines so we can test or inspect them if we make such a request.

• We are changing the definition of nonroad engine to explicitly exclude aircraft engines. This is consistent with our longstanding interpretation of the Clean Air Act. Clarifying the definition this way allows us to more clearly specify the applicability of the fuel requirements to nonroad engines in this final rule.

• We are adding a provision directing equipment manufacturers to request duplicate labels from engine manufacturers and keep appropriate records if the original label is obscured in the final installation. The former approach under 40 CFR part 1068 was to require equipment manufacturers to make their own duplicate labels as needed. We intend to amend 40 CFR parts 1048 and 1051 to correspond with this change.

• As described above in section III, we are revising the criteria manufacturers would use to show that they may use the replacement-engine exemption under 40 CFR 1068.240. We also clarify that we may require manufacturers to report to us how many engines they sell in given year under the replacement-engine exemption.

• As described above and in the Summary and Analysis of Comments, we are adding a provision in 40 CFR 1068.260 to allow manufacturers to ship aftertreatment devices directly from the component supplier to the equipment manufacturer. This regulatory section includes several provisions to ensure that the equipment manufacturer installs the aftertreatment device in a way that brings the engine to its certified configuration.

• As described above, we are modifying the defect-reporting requirements in 40 CFR 1068.501.

• While most of the changes being adopted for part 1065 will only affect diesel nonroad engines, we are also making minor changes that will also apply for SI engines. These changes, however, are generally limited to clarifications, corrections, and options. They will not affect the stringency of the standards or create new burdens for manufacturers.

IV. Our Program for Controlling Nonroad, Locomotive and Marine Diesel Fuel Sulfur

We are finalizing today a two-step sulfur standard for nonroad, locomotive and marine (NRLM) diesel fuel that will achieve significant, cost-effective sulfate PM and SO_2 emission reductions. These emission reductions will, by themselves, provide dramatic environmental and public health benefits which far outweigh the cost of meeting the standards necessary to achieve them. In addition, the final sulfur standards for nonroad diesel fuel will enable advanced high efficiency emission control technology to be applied to nonroad engines. As a result, these nonroad fuel sulfur standards, coupled with our program for more stringent emission standards for new nonroad engines and equipment, will also achieve dramatic NO_X and PM emission reductions. Sulfur significantly inhibits or impairs the function of the diesel exhaust emission control devices which will generally be necessary for nonroad diesel engines to meet the emission standards finalized today. With the 15 ppm sulfur standard for nonroad diesel fuel, we have concluded that this emission control technology will be available for model year 2011 and later nonroad diesel engines to achieve the NO_X and PM emission standards adopted today. The benefits of today's program also include the sulfate PM and SO_2 reductions achieved by establishing the same standard for the sulfur content of locomotive and marine diesel fuel.

The sulfur requirements established under today's program are similar to the sulfur limits established for highway diesel fuel in prior rulemakings —500 ppm in 1993 (55 FR 34120, August 21, 1990) and 15 ppm in 2006 (66 FR 5002, January 18, 2001). Beginning June 1, 2007, refiners will be required to produce NRLM diesel fuel with a maximum sulfur content of 500 ppm. Then, beginning June 1, 2010, the sulfur content will be reduced for nonroad diesel fuel to a maximum of 15 ppm. The sulfur content of locomotive and marine diesel fuel will be reduced to 15 ppm beginning June 1, 2012. The program contains certain provisions to ease refiners' transition to the lower sulfur standards and to enable the efficient distribution of all diesel fuels. These provisions include the 2012 date for locomotive and marine diesel fuel, early credits for refiners and importers and special provisions for small refiners, transmix processors, and entities in the fuel distribution system.

In general, the comments we received during the public comment period supported the proposed program. Adjustments we have made to the proposed program will make the final program even stronger, both in terms of our ability to enforce it and the environmental and public health benefits that it will achieve. In particular, today's final program contains provisions to smooth the refining industry's transition to the low sulfur fuel requirements, encourage earlier introduction of cleaner burning fuel, maintain the fuel distribution system's flexibility to fungibly distribute similar products, and provide an outlet for off-specification distillate product, all while maintaining, and even enhancing, the health and environmental benefits of today's program.

The first adjustment that we made to the proposed program was to move from the "refiner baseline" approach discussed in the proposal to a "designate and track" approach. Under the proposed refiner baseline approach, any refiner or importer could choose to fungibly distribute its 500 ppm sulfur NRLM and highway diesel fuels without adding red dye to the NRLM at the refinery gate. However, the refiners' production would then be subject to a non-highway distillate baseline, established as a percentage of its total distillate fuel production volume. While EPA preferred this approach in the proposal, we decided not to finalize it because we concluded that it would have unnecessarily constrained refiners' ability to meet market demands. It would have encouraged them to dye 500 ppm sulfur NRLM at the refinery gate, resulting in an additional grade of diesel fuel and, consequently, an added burden to the distribution system. Furthermore, we were concerned that it would have created a trend that could reduce the volume of 15 ppm sulfur highway diesel fuel and potential options to remove the market constraints could have increased the possibility for reduced volume.

In place of the refiner baseline approach, we are finalizing a designate and track approach. The final designate and track approach is a modified version of the designate and track approach discussed in the proposal. As finalized it now allows us to enforce the program through the entire distribution system. In essence, the final designate and track approach requires refiners and importers to designate the volumes of diesel fuel they produce and/or import. Refiners/importers will identify whether their diesel fuel is highway or NRLM and the applicable sulfur level. They may then mix and fungibly ship highway and NRLM diesel fuels that meet the same sulfur specification without dyeing their NRLM diesel fuel at the refinery gate. The designations will follow the fuel through the distribution system with limits placed on the ability of downstream parties to change the designation. These limits are designed to restrict the inappropriate sale of 500 ppm sulfur NRLM diesel fuel into the highway market , the inappropriate sale of heating oil into the NRLM market, the inappropriate sale of 500 ppm sulfur LM into the nonroad market, and to implement the downgrading restrictions that apply to 15 ppm sulfur highway diesel fuel. The designate and track approach includes record keeping and reporting requirements for all parties in the fuel distribution system, associated with tracking designated fuel volumes through each custodian in the distribution chain until the fuel exits the terminal. The program also includes enforcement and compliance assurance provisions to enable the Agency to rapidly and accurately review for discrepancies the large volume of data collected on fuel volume hand-offs. The bulk of the designate and track provisions end May 31, 2010 when all highway diesel fuel must meet the 15 ppm sulfur standard. However, as discussed below, scaled back designate and track provisions continue beyond 2010 for purposes of enforcing against heating oil being used in the NRLM market and to enforce against 500 ppm LM diesel fuel being used in the nonroad market.

The second adjustment that we made to the proposed NRLM diesel fuel program was to establish a 15 ppm sulfur standard at the refinery gate for locomotive and marine (LM) diesel fuel in addition to nonroad (NR) diesel fuel.[89] We are finalizing this standard for several reasons as discussed below.

While we are finalizing a 15 ppm sulfur standard for locomotive and marine diesel fuel, we are doing so in a manner that responds to the primary concerns raised in comments regarding the need for an outlet for off-specification product. We are setting a refinery gate standard of 15 ppm sulfur beginning June 1, 2012, two years later than for nonroad diesel fuel. We are also continuing to provide an outlet for off-specification product generated in the distribution system, thereby affording the opportunity to reduce reprocessing and transportation costs. We are leaving the downstream standard for LM diesel fuel at 500 ppm sulfur. In this way the LM diesel fuel pool may remain an outlet for off-specification distillate product and interface/transmix material.

In developing the provisions of the NRLM diesel fuel program adopted today, we identified several principles that we want the program to achieve. Specifically, as described in more detail below, we believe the fuel program—

(1) Achieves the greatest reduction in sulfate PM and SO_2 emissions from nonroad, locomotive, and marine diesel engines as early as practicable;

(2) Provides for a smooth transition of the NRLM diesel fuel pool to 15 ppm sulfur;

(3) Ensures that 15 ppm sulfur diesel fuel is produced and distributed widely for use in all 2011 and later model year nonroad diesel engines;

(4) Ensures that the fuel program's requirements are enforceable and verifiable.

(5) Enables the efficient distribution of all diesel fuels; and

(6) Maintains the benefits and program integrity of the highway diesel fuel program.

The remainder of this section covers several topics. In section IV.A, we discuss the fuel that is covered by today's program, the standards that apply for refiners and importers (for both steps of the program), and the standards that apply for downstream entities. In section IV.B, we address the various hardship provisions that we are including in today's program. In section IV.C, we describe the special provisions that apply in the State of Alaska and the Territories. Next, in section IV.D, we describe the design of the designate and track provisions of the NRLM diesel fuel program for compliance purposes and how it differs from what we proposed. In section IV.E, we discuss the impact of today's program on state NRLM diesel fuel programs. In sections IV.F and G, we discuss the technological feasibility of the NRLM diesel fuel standards adopted today and the impacts of today's program on lubricity and other fuel properties. Finally, in section IV.H, we discuss the steps the Agency will take to streamline the refinery air permitting process for the equipment that refiners may need to install to meet today's NRLM diesel fuel standards..

Analyses supporting the design and cost of the fuel program are located in chapters 5, 7, and 8 of the RIA. Section V of this preamble discusses the details of the additional compliance and enforcement provisions affecting NRLM diesel fuel and explains various additional elements of the program.

A. Nonroad, Locomotive and Marine Diesel Fuel Quality Standards

1. What Fuel Is Covered by This Program?

The fuel covered by today's final rule is generally the same as the fuel that was covered by the proposal. We have not expanded or reduced the pool of diesel fuel that will be subject to the lower sulfur standards. However, the second step of the program now includes the same ultra low sulfur standard for locomotive and marine diesel fuel as for nonroad diesel fuel.

[89] While today's program does not establish more stringent emission standards for locomotive or marine diesel engines, the Agency intends in the near future to initiate a rulemaking to adopt new emission standards for locomotive and marine engines based on the use of high efficiency exhaust emission control technology like that required for the nonroad standards adopted in today's rule. An advanced notice of proposed rulemaking (ANPRM) for this rule is published elsewhere in today's **Federal Register**, June 29, 2004.

Specifically, the sulfur standards finalized under today's program apply to all the diesel fuel that is used in nonroad, locomotive, and marine diesel applications—fuel not already covered by the previous standards for highway diesel fuel. This includes all fuel used in nonroad, locomotive, and marine diesel engines, except for fuels heavier than a No. 2 distillate used in Category 2 and 3 marine engines [90] and any fuel that is exempted for national security or other reasons. While we are not adopting sulfur standards for other distillate fuels (such as jet fuel, heating oil, kerosene, and No. 4 fuel oil) we are adopting provisions to prevent the inappropriate use of these other fuels. Use of distillate fuels in nonroad, locomotive, or marine diesel engines will generally be prohibited unless they meet the fuel sulfur standards finalized today.[91] The program includes several provisions, as described below in section IV.D, to ensure that heating oil and other higher sulfur distillate fuels will not be used in nonroad, locomotive, or marine applications.

The regulated fuels under today's program include the following:

(1) Any No. 1 and 2 distillate fuels used, intended for use, or made available for use in nonroad, locomotive, or marine diesel engines. Fuels under this category include those meeting the American Society for Testing and Materials (ASTM) D 975 or D 396 specifications for grades No. 1–D and No. 2–D. Fuels meeting ASTM DMX and DMA specifications would be covered;

(2) Any No. 1 distillate fuel (*e.g.*, kerosene) added to such No. 2 diesel fuel, *e.g.*, to improve its cold flow properties;

(3) Any other fuel used in nonroad, locomotive, or marine diesel engines or blended with diesel fuel for use in such engines. Fuels under this category include non-distillate fuels such as biodiesel and certain specialty fuel grades such as JP–5, JP–8, and F76 if used in a nonroad, locomotive, or marine diesel engine, except when a national security or research and development exemption has been approved. See V. A.1. and 2.

On the other hand, the sulfur standards do not apply to—

(1) No. 1 distillate fuel used to power aircraft;

(2) No. 1 or No. 2 distillate fuel used for stationary source purposes, such as to power stationary diesel engines, industrial boilers, or for heating;

(3) Number 4, 5, and 6 fuels (*e.g.*, residual fuels or residual fuel blends, IFO Heavy Fuel Oil Grades 30 and higher), used for stationary source purpose;

(4) Any distillate fuel with a T–90 distillation point greater than 700 F, when used in Category 2 or 3 marine diesel engines. This includes Number 4, 5, and 6 fuels (*e.g.*, IFO Heavy Fuel Oil Grades 30 and higher), as well as fuels meeting ASTM specifications DMB, DMC, and RMA–10 and heavier; and

(5) Any fuel for which a national security or research and development exemption has been approved or fuel that is exported from the U.S. (see section V.A.1. and 2).

It is useful to clarify what marine diesel fuels are covered by the sulfur standards. As with nonroad and locomotive diesel fuel, our basic approach is that the standards apply to any diesel or distillate fuel used or intended for use in marine diesel engines. However, the fuel used by marine diesel engines spans a wide variety of fuels, ranging from No. 1 and 2 diesel fuel to residual fuel and residual fuel blends used in the largest engines. It is not EPA's intention to cover all such fuels, and EPA has adopted an objective criteria to identify those marine fuels subject to regulation and those that are not. Any distillate fuel with a T–90 greater than 700 F will not be subject to the sulfur standards when used in Category 2 or 3 marine engines. This criteria is designed to exclude fuels heavier than No. 2 distillate, including blends containing residual fuel. In addition, residual fuel is not subject to the sulfur standards.

While many marine diesel engines use No. 2 distillate, ASTM specifications for marine fuels identify four kinds of marine distillate fuels: DMX, DMA, DMB, and DMC. DMX is a special light distillate intended mainly for use in emergency engines. DMA (also called MGO) is a general purpose marine distillate that is to contain no traces of residual fuel. These fuels can be used in all marine diesel engines but are primarily used by Category 1 engines. DMX and DMA fuels intended for use in any marine diesel engine are subject to the fuel sulfur standards.

DMB, also called marine diesel oil, is not typically used with Category 1 engines, but is used for Category 2 and 3 engines. DMB is allowed to have a trace of residual fuel, which can be high in sulfur. This contamination with residual fuel usually occurs due to the distribution process, when distillate is brought on board a vessel via a barge that has previously contained residual fuel, or using the same supply lines as are used for residual fuel. DMB is produced when fuels such as DMA are brought on board the vessel in this manner. EPA's sulfur standards will apply to the distillate that is used to produce the DMB, for example the DMA distillate, up to the point that it becomes DMB. DMB itself is not subject to the sulfur standards when it is used in Category 2 or 3 engines.

DMC is a grade of marine fuel that may contain some residual fuel and is often a residual fuel blend. This fuel is similar to No. 4 diesel, and can be used in Category 2 and Category 3 marine diesel engines. DMC is produced by blending a distillate fuel with residual fuel, for example at a location downstream in the distribution system. EPA's standards will apply to the distillate that is used to produce the DMC, up to the point that it is blended with the residual fuel to produce DMC. DMC itself is not subject to the sulfur standards when it is used in Category 2 or 3 marine engines.

Residual fuel is typically designated by the prefix RM (*e.g.*, RMA, RMB, etc.). These fuels are also identified by their nominal viscosity (*e.g.*, RMA10, RMG35, etc.). Most residual fuels require treatment by a purifier-clarifier centrifuge system, although RMA and RMB do not require this. For the purpose of this rule, we consider all RM grade fuel as residual fuel. Residual fuel is not covered by the sulfur content standards as it is not a distillate fuel.

The distillation criteria adopted by EPA, T–90 greater than 700F, is designed to identify those fuels that are not subject to the sulfur standards when used in Category 2 or 3 marine diesel engines. It is intended to exclude DMB, DMC, and other heavy distillates or blends, when used in Category 2 or 3 marine diesel engines.

Hence, the fuel that refiners and importers are required to produce to the more stringent sulfur standards include those No. 1 and No. 2 diesel fuels as well as similar distillate or non-distillate fuels that are intended or made available for use in NRLM diesel engines. Furthermore, the sulfur standard also covers any fuel that is blended with or substituted for No. 1 or No. 2 diesel fuel for use in nonroad, locomotive, or marine diesel engines. For instance, as required under the highway diesel fuel program, in those situations where the same batch of kerosene is distributed for two purposes (*e.g.*, kerosene to be used for heating and to improve the cold flow of No. 2 NRLM diesel fuel), or where a batch distributed just for heating is later distributed for blending with No. 2 diesel fuel, that batch of kerosene must meet the standards adopted today for NRLM

[90] Category 3 marine engines frequently are designed to use residual fuels and include special fuel handling equipment to use the residual fuel.

[91] For the purposes of this final rule, the term heating oil basically refers to any No. 1 or No. 2 distillate other than jet fuel, kerosene, and diesel fuel used in highway, nonroad, locomotive, or marine applications. For example, heating oil includes fuel which is suitable for use in furnaces, boilers, stationary diesel engines and similar applications and is commonly or commercially known or sold as heating oil, fuel oil, or other similar trade names.

diesel fuel. The purpose of this requirement is to ensure that fuels like jet fuel, kerosene, and/or military specification fuels meet the diesel fuel sulfur standards adopted under today's program when they are used in nonroad, locomotive, or marine diesel engines.

2. Standards and Deadlines for Refiners and Importers

The NRLM diesel fuel program adopted today is a two-step approach to reduce the sulfur content of NRLM diesel fuel from uncontrolled levels down to 15 ppm sulfur. While we received several comments supporting a single step down to 15 ppm sulfur, the vast majority of commenters, especially most refiners and engine manufacturers, supported the two-step approach. We are finalizing the two-step approach primarily because it achieves the greatest reduction in sulfate PM and SO_2 emissions from nonroad, locomotive, and marine diesel engines as early as practicable. By starting with an initial step of 500 ppm sulfur we can achieve significant emission reductions and associated health and welfare benefits from the current fleet of equipment as soon as possible. As discussed in section VI, the health-related benefits of the fuel standards finalized today, even without the engine standards, amount to more than $28 billion in 2030, while the projected costs, after taking into account engine maintenance benefits amount to just $0.7 billion.

In addition, the two-step approach encourages a more smooth and orderly transition by the refining industry to 15 ppm sulfur NRLM diesel fuel, by providing more time for refiners to develop the most cost-effective approaches, finance them, and then implement the necessary refinery modifications.

Finally, by waiting until 2010 to drop to the 15 ppm sulfur standard for NR diesel fuel, the two-step approach harmonizes with the highway diesel fuel program by delaying the implementation of the 15 ppm sulfur standard for NR diesel fuel until the end of the phase-in period for 15 ppm sulfur highway diesel fuel. The 2010 date also harmonizes with the date 15 ppm nonroad fuel is needed to enable the nonroad engines standards finalized today. The second step to 15 ppm sulfur for the LM diesel fuel is set for 2012. On balance we believe that the advantages of the two-step approach outweigh those of a single step down to 15 ppm.

As discussed in section IV.C, below, later deadlines for meeting the 500 and 15 ppm sulfur standards apply to refineries covered by special hardship provisions as well as transmix processors.

a. The First Step to 500 ppm Sulfur NRLM Diesel Fuel

Under today's program, NRLM diesel fuel produced by refiners or imported into the U.S. by importers must meet a 500 ppm sulfur standard beginning June 1, 2007. Refiners and importers may comply by either producing such fuel at or below 500 ppm sulfur, or they may comply by obtaining credits as discussed in section IV.D below.

We believe that the adopted level of 500 ppm sulfur is appropriate for several reasons. First, the reduction to 500 ppm sulfur is significant environmentally. The 500 ppm sulfur level achieves approximately 90 percent of the sulfate PM and SO_2 benefits otherwise achievable by going all the way to 15 ppm sulfur. Second, because this first step is only to 500 ppm sulfur, it also allows for a short lead time for implementation, enabling the environmental benefits to begin accruing as soon as possible. Third, it is consistent with the current specification for highway diesel fuel, a grade which may remain for highway purposes until 2010. As such, adopting the same 500 ppm sulfur level for NRLM diesel fuel helps to avoid issues and costs associated with more grades of fuel in the distribution system during this initial step of the program.

b. The Second Step to 15 ppm Sulfur NRLM Diesel Fuel

We are finalizing a second step of sulfur control down to 15 ppm sulfur for all NRLM. This second step provides additional important direct sulfate PM and SO_2 emission reductions and associated health benefits. As discussed in the RIA, the health related benefits for this second step of fuel control by itself are greater than the associated cost. Furthermore, the second step for nonroad diesel fuel is essential to enable the application of high efficiency exhaust emission control technologies to nonroad diesel engines beginning with the 2011 model year as discussed in Section II of this preamble.

In the proposal, the second step of the program only applied to nonroad diesel fuel, while locomotive and marine diesel fuel could remain at 500 ppm sulfur. We also sought comment on finalizing the 15 ppm sulfur standard for LM diesel fuel in 2010 along with nonroad diesel fuel, as well as delaying it until as late as 2012 to allow for an additional outlet for any off-specification product a refinery might produce as it shifts all of its distillate production to 15 ppm sulfur.[92]

We are finalizing the 15 ppm sulfur standard for locomotive and marine diesel fuel, along with nonroad diesel fuel, for several reasons. First, it will provide important health and welfare benefits from the additional sulfate PM and SO_2 emission reductions as early as possible. Second, it is technologically feasible, as it is for nonroad diesel fuel. Third, the benefits outweigh the costs and the costs do not otherwise warrant delaying this second step for locomotive and marine. As shown in chapter 8 of the RIA, the costs for the increment of LM diesel fuel going from 500 to 15 ppm sulfur is just $0.20 billion in 2030. Fourth, it will simplify the fuel distribution system and overall design of the fuel program. For example, the addition of a marker to locomotive and marine diesel fuel after 2012 is no longer necessary to successfully enforce the program. Finally, it will allow refiners to coordinate plans to reduce the sulfur content of all of their off-highway diesel fuel at one time.

Our primary reason in the NPRM for leaving locomotive and marine diesel fuel at the 500 ppm sulfur specification was to preserve an outlet for off-specification product that may be created in the distribution system through contamination of 15 ppm sulfur diesel fuel with higher sulfur distillates and for off-specification batches of fuel that are produced by refineries during the first couple years of the 15 ppm sulfur program (when they are still perfecting their production processes). However, we have concluded that it is not necessary to leave the standard for all locomotive and marine diesel fuel at the 500 ppm sulfur specification to address these concerns. Setting a 15 ppm sulfur standard for refiners and importers in 2012, but maintaining a downstream standard for locomotive and marine diesel fuel at 500 ppm sulfur and allowing off-specification product to continue to be sold into this market accomplishes the same goal.

In addition, controlling the sulfur content of NRLM diesel fuel from uncontrolled levels to 15 ppm is clearly a cost-effective fuel control program. While the incremental cost-effectiveness from 500 ppm sulfur to 15 ppm sulfur is less cost-effective, the benefits of this second step outweigh the costs, the concerns about a market for off-specification product have been addressed, and other factors discussed

[92] Off-specification fuel here refers to 15 ppm diesel fuel that becomes contaminated such that it no longer meets the 15 ppm sulfur cap. In most cases, off-specification 15 ppm sulfur diesel fuel is expected to easily meet a 500 ppm sulfur cap.

above support the reasonableness of this approach. The body of evidence strongly supports the view that controlling sulfur in NRLM fuel to 15 ppm, through a two-step process, is quite reasonable in light of the emissions reductions achieved, taking costs into consideration.

Implementation of today's rule will reduce the sulfur level of almost all distillate fuel to a 15 ppm maximum sulfur level. In addition to the small refiner, hardship, and other provisions adopted in this rule, EPA is adopting several provisions that will help ensure a smooth transition to the second step of 15 ppm sulfur diesel fuel. First, refiners and importers of locomotive and marine diesel fuel, a small segment of the entire distillate pool, will be required to meet a 15 ppm sulfur standard starting June 1, 2012, two years later than for nonroad diesel fuel. Second, 500 ppm sulfur diesel fuel generated in the distribution system through contamination of 15 ppm sulfur fuel can be marketed in the nonroad, locomotive and marine market until June 2014, and in the locomotive and marine market after that date. Third, 500 ppm sulfur diesel fuel produced by transmix processors from contaminated downstream diesel fuel can also be marketed to the nonroad, locomotive and marine markets, under the same schedule. While today's rule does not contain an end date for the downstream distribution of 500 ppm sulfur locomotive and marine fuel, we will review the appropriateness of allowing this flexibility based on experience gained from implementation of the 15 ppm sulfur NRLM diesel fuel standard. We expect to conduct such an evaluation in 2011.

When EPA adopted a 15 ppm sulfur standard for highway diesel fuel, we included several provisions to ensure a smooth transition to 15 ppm sulfur highway fuel. One provision was a temporary compliance option, with an averaging, banking and trading component. In a similar manner, the 2012 deadline for 15 ppm sulfur LM fuel, the last, relatively small segment of diesel fuel, will help ensure that the entire pool of diesel fuel is smoothly transitioned to the 15 ppm sulfur level over a short period of time. (See section 8.3 of the summary and analysis of comments.)

EPA is also adopting two provisions aimed at smoothing the transition of the distribution system to ultra low sulfur diesel fuel. These provisions are designed to accommodate off-specification fuel generated in the distribution system, such as through the mixing that occurs at product interfaces. This off-specification material generally cannot be added in any significant quantity to either of the adjoining products that produced the interface.[93] Under today's program, as discussed in more detail in section A.3, below, off-specification material that is generated in the distribution system may be distributed as 500 ppm NRLM diesel fuel from June 1, 2010 through May 31, 2014 and as 500 ppm LM from June 1, 2014 and beyond. Furthermore, as discussed in section IV.C, below, transmix processors, which are facilities that process transmix by separating it into its components (*e.g.*, separating gasoline from diesel fuel), are treated as a separate class of refiners. One hundred percent of the diesel fuel they produce from transmix may be sold as high sulfur NRLM until June 1, 2010, 500 ppm sulfur NRLM until June 1, 2014, and 500 ppm sulfur LM diesel fuel after June 1, 2014.

These provisions provide refiners and importers with a similar degree of flexibility for off-specification product as the proposal which held the sulfur standard for all locomotive and marine diesel fuel at 500 ppm indefinitely. If off-specification product is produced, there is a temporary outlet for it. If providing the off-specification product to a locomotive and marine market is difficult under this final rule, such that a refiner will choose to re-process it, then the refiner would have been in the same position under the proposal. Furthermore, these provisions provide the refining industry an alternative to reprocessing the off-specification material created in the distribution system, which preserves refining capacity for the production of new fuel volume, helping to maintain overall diesel fuel supply.

As with the 500 ppm sulfur standard under the first step of today's program, refiners and importers may comply with the 15 ppm sulfur standard by either producing NRLM diesel fuel containing no more than 15 ppm sulfur or by obtaining sulfur credits (until June 1, 2014), as described below.

c. Cetane Index or Aromatics Standard

Currently, in addition to containing no more than 500 ppm sulfur, highway diesel fuel must meet a minimum cetane index level of 40 or, as an alternative, contain no more than 35 volume percent aromatics. Today's program extends this cetane index/aromatics content specification to NRLM diesel fuel.

One refining company commented that EPA should not implement the cetane index and aromatic requirements in the proposed rule since the impacts are weak or nonexistent for engines to be used in the future. In addition, the commenter stated that the vast majority of diesel fuel already meets the EPA cetane index/aromatics specification for highway diesel fuel and that there is nothing in the RIA that either demonstrates the benefits or supports the need for such a requirement. The commenter also stated that EPA should not set a requirement simply because the ASTM standard has a cetane number specification for a particular fuel.

Low cetane levels are associated with increases in NO_X and PM emissions from current nonroad diesel engines.[94] Thus, we expect that extending the cetane index specification to NRLM diesel fuel will directionally lead to a reduction in these emissions from the existing fleet. However, because the vast majority of NRLM diesel fuel already meets the specification, the NO_X and PM emission reductions will be small. At the same time, the refining/production costs associated with extending the cetane index specification to NRLM diesel fuel are negligible as current NRLM diesel fuel already meets a more stringent ASTM specification.

ASTM already recommends a cetane number specification of 40 for NRLM diesel fuel, which is, in general, more stringent than the similar 40 cetane index specification. Because of this, the vast majority of current NRLM diesel fuel already meets the EPA cetane index/aromatics specification for highway diesel fuel. Thus, the cetane index specification will impact only a few refiners and there will be little overall cost associated with producing fuel to meet the cetane/aromatic requirement. In fact, as discussed in chapter 5.9 of the RIA, compliance with the sulfur standards adopted today is expected to result in a small cetane increase as increases in cetane correlate with decreases in sulfur, leaving little or no further control to meet the standard.

While the emissions benefits and refining/production costs of extending the specification to NRLM diesel fuel may be small, the extension will reduce costs by giving refiners and distributors the ability to fungibly distribute highway and NRLM diesel fuels of like sulfur content. For that small fraction of NRLM diesel fuel today that does not meet the cetane index or aromatics

[93] In some cases the off-specification product can not be added to the adjoining products because of the applicable sulfur standards. In other cases, the off-specification product, called transmix, must be re-processed before it can be used.

[94] *The Effect of Cetane Number Increase Due to Additives on NO_X Emissions From Heavy-Duty Highway Engines, Final Technical Report*, February 2003, EPA420–R–03–002.

specification, the requirement will eliminate the need for refiners and fuel distributors to separately distribute fuels of different cetane/aromatics specifications. Requiring NRLM diesel fuel to meet this cetane index specification thus gives fuel distributors certainty in being able to combine shipments of highway and NRLM diesel fuels. Perhaps more importantly, it can also give engine manufacturers and end-users the confidence they need that their fuel will meet the minimum cetane or maximum aromatics standard. Given the inherent difficulty in segregating two otherwise identical fuels, were we not to carry over these standards to NRLM, lower cetane NRLM could easily find its way into current highway engines. If not designed for this lower cetane fuel, these engines could have elevated emission levels and performance problems.

Overall, we believe that there will be a small reduction in NO_X and PM emissions from current engines and the economic benefits from more efficient fuel distribution will likely exceed the cost of raising the cetane level for the small volume of NRLM diesel fuel that does not already meet the cetane index or aromatics content specification.

3. Standards, Deadlines, and Flexibilities for Fuel Distributors

The first years of the NRLM diesel fuel program include various flexibilities to smooth the refining and distribution industry's transition to 15 ppm sulfur fuel. These flexibilities include a 2012 deadline for production of 15 ppm sulfur locomotive and marine diesel fuel, credit provisions, small refiner provisions, hardship provisions, and downstream off-specification fuel provisions. As a result, during the transition years, we are not able to simply enforce the sulfur standards downstream based on a single sulfur level of the new standard. From June 1, 2007 through May 31, 2010, both 500 ppm sulfur diesel fuel and high sulfur diesel fuel can be produced, distributed, and sold for use in NRLM diesel engines. From June 1, 2010 through May 31, 2014, both 15 ppm sulfur and 500 ppm sulfur diesel fuel can be produced, distributed, and sold for use in NRLM diesel engines. Beyond June 1, 2014, both 15 ppm sulfur and 500 ppm sulfur diesel fuel that is produced from fuel product downgrade and transmix in the distribution system can be distributed and sold for use in locomotive and marine diesel engines. As these transition flexibilities expire, however, we are able to streamline our downstream enforcement provisions.

a. Standards and Deadlines From June 1, 2007 Through May 31, 2010

As soon as the program begins on June 1, 2007, all NRLM diesel fuel must be designated or classified and must comply with the designation or classification stated on its product transfer document (PTD), pump label, or other documentation. In other words, if the fuel is intended for sale as NRLM diesel fuel and is labeled as 500 ppm sulfur diesel fuel, then beginning June 1, 2007, it must comply with the 500 ppm sulfur standard. Similarly, if fuel is intended for sale as NRLM diesel fuel and is labeled as 15 ppm sulfur, then beginning June 1, 2010 (or June 1, 2009 under the early credit provisions), it must comply with the 15 ppm sulfur standard.

Beginning June 1, 2010, all NRLM diesel fuel produced or imported is required to meet at least a 500 ppm sulfur limit. In order to allow for a smooth and orderly transition to 500 ppm sulfur NRLM diesel fuel in the distribution system, and allow any remaining high sulfur fuel to be sold, we are providing parties downstream of refineries time to turnover their NRLM tanks to 500 ppm sulfur diesel fuel. At the terminal level, all NRLM diesel fuel must meet at least the 500 ppm sulfur standard beginning August 1, 2010. At any wholesale purchaser-consumer facilities and any retail stations carrying NRLM diesel fuel, including bulk plants that serve as retailers, all diesel fuel must meet the 500 ppm sulfur standard beginning October 1, 2010.[95] Thus, beginning October 1, 2010, high sulfur (greater than 500 ppm sulfur) NRLM diesel fuel may no longer legally exist in the fuel distribution system.[96]

Although we expect that most NRLM diesel fuel in the distribution system will be subject to the 500 ppm sulfur standard during the period from June 1, 2007 through May 31, 2010, based on its designation or classification, some of the 500 ppm sulfur NRLM diesel fuel may be mixed with high sulfur NRLM diesel fuel. Since the blended product will likely no longer meet the 500 ppm sulfur standard, it must be re-designated and labeled as high sulfur NRLM diesel fuel. Similarly, fuel that results from blending 500 ppm sulfur NRLM diesel fuel and heating oil must be re-designated and labeled as heating oil.

b. Standards and Deadlines From June 1, 2010 Through May 31, 2014

Beginning June 1, 2010, most NR diesel fuel will be required to meet the 15 ppm sulfur standard, and beginning June 1, 2012, most LM diesel fuel will be required to meet the 15 ppm sulfur standard. However, some production of 500 ppm sulfur NRLM diesel fuel may continue through May 31, 2014. As with the delayed downstream compliance dates for the 500 ppm sulfur standard under the first step of today's program, parties downstream of refineries will be allowed additional time to turnover their tanks to 15 ppm sulfur NR diesel fuel. Specifically, at the terminal level, all NR diesel fuel will be required to meet the 15 ppm sulfur standard beginning August 1, 2014. At any wholesale purchaser-consumer facilities and retail stations carrying all NR diesel fuel, including bulk plants serving as retailers, NR diesel fuel must meet the 15 ppm sulfur standard beginning October 1, 2014. Thus, beginning October 1, 2014, 500 ppm sulfur NR diesel fuel may no longer legally exist in the fuel distribution system.[97]

Like the first step to 500 ppm sulfur, prior to these 2014 downstream deadlines all NRLM diesel fuel would still be designated or classified with respect to sulfur level and required to meet the designation or classification stated on its PTD, pump label, or other documentation.

c. Sulfur Standard for NRLM Diesel Fuel Beginning June 1, 2014

As discussed above, all refiners will be required to produce and importers will be required to import only 15 ppm sulfur NRLM diesel fuel by June 1, 2014. However, we will continue to allow 500 ppm sulfur diesel fuel to be sold into the LM diesel fuel markets beyond 2014. The LM diesel fuel markets are expected to provide a valuable outlet for higher sulfur distillate fuel produced in the distribution system, at least through the early years of the program. Consequently, beyond 2014, both 15 ppm sulfur and 500 ppm sulfur LM diesel fuel may continue to exist in the distribution system, and each fuel must comply with the designation stated on its PTD, pump label, or other documentation.

[95] A bulk plant is a secondary distributor of refined petroleum products. They typically receive fuel from terminals and distribute fuel in bulk by truck to end users. Consequently, while for highway fuel, bulk plants often serve the role of a fuel distributor, delivering fuel to retail stations, for nonroad fuel, they often serve the role of the retailer, delivering fuel directly to the end-user.

[96] By December 1, 2010, all NRLM diesel fuel, including fuel in end-user tanks, must comply with at least the 500 ppm sulfur standard.

[97] By December 1, 2014, all NR diesel fuel, including fuel in end-user tanks, must comply with at least the 15 ppm sulfur standard.

d. Interface/Transmix Flexibility for Fuel Distributors

As described above, today's program provides flexibility to the distribution system by allowing interface/transmix material generated within the distribution system to be sold into the NRLM diesel fuel markets. Specifically, any fuel interface/transmix generated in the fuel distribution system may be sold as:

(1) High sulfur NRLM diesel fuel or heating oil from June 1, 2007 through May 31, 2010;

(2) 500 ppm sulfur NRLM diesel fuel or heating oil from June 1, 2010 through May 31, 2014; or

(3) 500 ppm sulfur LM diesel fuel or heating oil after June 1, 2014.

Hence, beginning June 1, 2014, interface/transmix material exceeding 15 ppm sulfur may only be sold into the LM diesel fuel or heating oil markets. As discussed above, the downstream standard for LM diesel fuel will be 500 ppm sulfur. However, heating oil may not be shifted into the LM markets. Parties in the distribution system receiving diesel fuel with a sulfur content greater than 15 ppm sulfur must maintain records and report to EPA information demonstrating that they did not shift heating oil into the LM markets, as discussed in section IV.D.

The generation of greater than 15 ppm sulfur distillate fuel from pipeline interface/transmix cannot be avoided due to the physical realities of a multi-product fuel distribution system. Such fuel first appears at the terminus of the pipeline distribution system; at terminals due to the generation of segregated interface, or at transmix processing facilities.[98] In areas where there is a strong demand for heating oil, much of this pipeline-generated off-specification fuel can be sold into the heating oil market, just as it is today. However, in many areas of the country the demand for heating oil would not be sufficient to accommodate distillate fuel exceeding 15 ppm sulfur that is generated in the pipeline. Therefore, such fuel would need to be returned to a refinery for reprocessing to meet a 15 ppm sulfur standard. In addition, some refiners may be reluctant to accept such material for reprocessing given the impact this would have on their refinery operations. More importantly, because such material appears at the terminus of the pipeline distribution system and often where no access to pipeline or marine shipment is available, it would have to be shipped back to a refinery by truck, or rail if available, at additional cost.

As discussed in chapter 7 of the RIA, fuel generated from such interface/transmix will typically meet a 500 ppm sulfur standard. Therefore, allowing the continued use of such 500 ppm sulfur diesel fuel in locomotive and marine engines could reduce the burden on the fuel distribution industry by lowering costs. Our cost estimates of marketing such fuel include additional shipping charges for situations where there is not a local locomotive or marine market (see section VI of this preamble).[99] Allowing the continued sale of 500 ppm sulfur diesel fuel into the locomotive and marine markets without requiring it to be reprocessed will also help preserve refining capacity for the overall diesel fuel production. Therefore, this provision also serves to address lingering concerns expressed by some refiners regarding the impacts of the 15 ppm sulfur standard for highway and NRLM diesel fuel on overall diesel fuel supply.

Downstream-generated 500 ppm sulfur diesel fuel may only be used in nonroad engines until December 1, 2014, due to concerns regarding enforceability and the increased potential for misfueling of nonroad equipment (equipment with advanced emission controls). Beginning with the 2011 model year, such equipment will require the use of 15 ppm sulfur diesel fuel to operate properly. The same concerns do not exist regarding the continued use of such 500 ppm sulfur diesel fuel in locomotive and marine engines for three reasons. First, locomotive and marine engines are not currently required to be equipped with the sulfur sensitive emissions aftertreatment that will start being used on nonroad equipment in 2011.[100] Second, locomotive and marine markets are centrally fueled to a much greater extent than nonroad markets, and thus enforceability is not as significant of an issue. Finally, we believe the program's designate and track provisions discussed below will be sufficient to enforce the limits on production and use of 500 ppm sulfur diesel fuel.

It is difficult to project exactly how much of this downstream generated downgraded fuel could be segregated and shipped to LM markets. However, it is clear that this provision represents an important flexibility for the distribution system. In fact, it provides virtually the same flexibility as provided by the proposal to handle off-specification product. In both cases, use of the flexibility is dependent on the ability to segregate the interface and transport it to available LM markets. While today's rule does not contain an end date for the downstream distribution of 500 ppm sulfur locomotive and marine fuel, we will review the appropriateness of allowing this flexibility based on experience gained from implementation of the 15 ppm sulfur NRLM diesel fuel standard. We expect to conduct such an evaluation in 2011.

A summary of the NRLM sulfur levels and final deadlines for refiners, importers, terminals, and other downstream parties is shown in table IV–1 below.

TABLE IV–1.—500 PPM SULFUR AND 15 PPM SULFUR NRLM FINAL COMPLIANCE DATES

	Refiners and importers	Credit, small refiner	Terminals	Bulk plants, whole-sale purchaser-consumers and retail outlets	Other locations
500 ppm NRLM	June 1, 2007	June 1, 2010	August 1, 2010	October 1, 2010	December 1, 2010.
15 ppm NR	June 1, 2010	June 1, 2014	August 1, 2014	October 1, 2014	December 1, 2014.

[98] Segregated interface refers to the mixing zone between two batches of fuel that abut each other in the pipeline, where the volume in the mixing zone can not be cut into either of the fuel batches, but can still meet another fuel product specification without reprocessing, provided that it is drawn off of the pipeline separately and segregated.

[99] As mentioned above, the Agency intends in the near future to initiate a rulemaking to adopt new emission standards for locomotive and marine engines. An advanced notice of proposed rulemaking (ANPRM) for this rule is published elsewhere in today's **Federal Register**, June 29, 2004. While we are not finalizing a sunset date for this downgrade provision in today's final rule, we are evaluating the appropriateness of establishing a sunset date on this provision in the context of the subsequent engine standards rule. We also intend to review the appropriateness of any sunset provision in light of experience gained from implementation of the 15 ppm sulfur NRLM diesel fuel standard. We would conduct such an evaluation in 2011.

[100] Although, as mentioned above, the Agency intends in the near future to initiate a rulemaking to adopt new emission standards for locomotive and marine engines. An advanced notice of proposed rulemaking (ANPRM) for this rule is published elsewhere in today's **Federal Register**, June 29, 2004.

TABLE IV–1.—500 PPM SULFUR AND 15 PPM SULFUR NRLM FINAL COMPLIANCE DATES—Continued

	Refiners and importers	Credit, small refiner	Terminals	Bulk plants, wholesale purchaser-consumers and retail outlets	Other locations
15 ppm LM	June 1, 2012	June 1, 2014.			

4. Diesel Sulfur Credit Banking and Trading Provisions

Today's final program includes provisions for refiners and importers to generate early credits for the production of 500 ppm sulfur NRLM diesel fuel prior to June 1, 2007 and for the production of 15 ppm sulfur NRLM diesel fuel prior to June 1, 2010. These credit banking and trading provisions will provide implementation flexibility by facilitating a somewhat smoother transition at the start of the program in 2007, with some refineries/import facilities complying early, others on time, and others a little later. These credit banking and trading provisions may also facilitate some of the environmental benefits of the program being achieved earlier than otherwise required, and may increase the overall environmental benefits of the program. As discussed below, overall benefits will accrue if refiners produce 500 ppm earlier in lieu of high sulfur NRLM and then bank those credits to continue producing 500 ppm sulfur NR diesel fuel in 2010 or 500 ppm LM diesel fuel in 2012 in lieu of 15 ppm.[101]

Specifically, credits generated under the NRLM diesel fuel program may be banked and later used to delay compliance with either the 500 ppm sulfur NRLM standard that begins in 2007, the 15 ppm sulfur NR standard that begins in 2010, or the 15 ppm sulfur LM standard that begins in 2012. Credits may also be traded within companies such that credits generated at one refinery/import facility in a given company may be traded to another refinery/import facility within that same company. In addition, refiners or importers may purchase credits generated by other refiners or importers to meet the program requirements. Finally, and perhaps most importantly, individual refineries/import facilities may be able to use credits to permit the continued sale of otherwise off-specification product at the beginning of the program's second step when they are still adjusting their operations for consistent production/importation of NRLM diesel fuel that is subject to the new sulfur standards.

a. Credit Generation From June 1, 2006 Through May 31, 2007

Credits may be generated under today's program to allow for the production of high sulfur NRLM diesel fuel after June 1, 2007. A refiner or importer may obtain credit for early production/importation of fuel meeting the 500 ppm sulfur standard that they designate as NRLM diesel fuel, from June 1, 2006 through May 31, 2007. In addition, small refiners may also generate credits for the early production of 500 ppm sulfur diesel fuel that they designate as NRLM diesel fuel. As described in section IV.B, below, small refiners are not required to produce any 500 ppm sulfur NRLM diesel fuel until June 1, 2010. Those small refiners who choose to comply with the 500 ppm sulfur standard earlier than required, that is before June 1, 2010, may generate credits for any volume of diesel fuel they produce from June 1, 2007 through May 31, 2010 and designate as NRLM. Credits for the early production of 500 ppm sulfur fuel (including by small refineries) are fungible, may be banked for future use, or traded to any other refiner or importer nationwide. In order to ensure that these early credits are real and not merely shifts from the highway market, both early credits and small refinery credits will be subject to a limit determined by the following formula:

$Credit_{HS} = (Vol_{15} + Vol_{500}) - Vol_{hwy}$

$Credit_{HS}\ Limit = (Vol_{15} + Vol_{500}) - Base_{hwy}$

Where:

$Credit_{500}$ Limit = Limit for 500 ppm NRLM credits

$Credit_{HS}$ = High-Sulfur NRLM credits[102]

Vol_{15} = Volume of 15 ppm sulfur diesel fuel produced and designated as highway or NRLM

Vol_{500} = Volume of 500 ppm sulfur diesel fuel produced and designated as highway or NRLM

$Base_{hwy}$ = 2003–2005 highway diesel fuel baseline volume

Vol_{hwy} = Volume of diesel fuel produced and designated as highway

If the excess production is 15 ppm sulfur diesel fuel instead of 500 ppm sulfur diesel fuel, then the refiner will have the option of generating 500 ppm sulfur credits under the highway diesel fuel program. Credit may not be earned under both programs for a given volume of 500 ppm sulfur or 15 ppm sulfur diesel fuel.

b. Credit Generation From June 1, 2009 Through May 31, 2010

In addition to allowing credit for the early production of 500 ppm sulfur NRLM diesel fuel, today's program also allows credit for the early production of 15 ppm sulfur NRLM diesel fuel. Specifically, refiners and importers may obtain credit for early production/importation of fuel meeting the 15 ppm sulfur standard and that they designate as NRLM from June 1, 2009 through May 31, 2010. In addition, small refiners, which are not required to produce any 15 ppm sulfur NRLM diesel fuel until June 1, 2014, may also generate credits for the early production of any volume of 15 ppm sulfur diesel fuel that they designate as NRLM from June 1, 2010 through December 31, 2013. Again, these early credits are fungible, may be banked for future use, or traded to any other refinery or importer nationwide. However, in order to ensure these credits are real and not merely shifts from the highway market, credits for the early production or importation of 15 ppm sulfur fuel will be subject to a limit determined by the following formula:

$Credit_{500} = Vol_{15} - Vol_{15hwy}$

$Credit_{500}\ Limit = Vol_{15} - Base_{15hwy}$

Where:

$Credit_{500}$ Limit = Limit for 500 ppm sulfur NRLM credits

Vol_{15} = Volume of 15 ppm sulfur diesel fuel produced and designated as highway or NRLM

$Base_{15hwy}$ = 2006–2008 15 ppm sulfur highway diesel fuel baseline volume

[101] We are not adopting specific provisions to generate credits for early production of LM diesel fuel prior to June 1, 2012. The difference in start date between 2010 and 2012 already provides additional flexibility to producers of LM diesel fuel, and setting separate credit generation periods for NR and LM diesel fuel would unnecessarily complicate the compliance assurance provisions.

[102] For the purposes of this rule, credits are labeled on the basis of their use in order to follow the convention used in the highway diesel rule. A high-sulfur credit is generated through the production of one gallon of 500 ppm sulfur NRLM diesel fuel and allows the production of one gallon of high sulfur NRLM diesel fuel.

Hence, to generate credits, a refiner or importer's highway diesel fuel volume for the compliance period must be greater than or equal to the baseline volume. That is, a refiner or importer may only generate credits for "new" volumes of 15 ppm sulfur diesel fuel that it produces. If their highway diesel fuel volume were to drop below the baseline volume, that would likely indicate a shift in production from the highway market to generate 15 ppm sulfur NRLM diesel fuel credits.

c. Credit Use

There are two ways in which refiners or importers may use high-sulfur NRLM credits under the NRLM diesel fuel program. First, credits may be used during the period from June 1, 2007 through May 31, 2010 to continue to produce high sulfur NRLM diesel fuel. Any high sulfur NRLM diesel fuel that is produced, however, must be designated and labeled as such for tracking purposes throughout the distribution system and be dyed red at the refinery gate.

The second way in which refiners and importer could use high-sulfur NRLM credits is by banking them for use during the June 1, 2010 through May 31, 2014 period. Credits used in this manner would provide a net environmental benefit, since they were generated by reducing the sulfur level from approximately 3000 ppm to less than 500 ppm (a net change of 2500 ppm sulfur), but when used only allow the sulfur level to increase from 15 ppm to 500 ppm (a net change of less than 500 ppm sulfur). 500 ppm sulfur credits generated from the early production of 15 ppm sulfur NRLM diesel fuel may also be used from June 1, 2010 through May 31, 2014. Thus, during this period, when the 15 ppm sulfur standard is in effect for nonroad diesel fuel, refiners/importers may use either high sulfur credits or 500 ppm sulfur credits to continue producing/importing 500 ppm sulfur nonroad diesel fuel. Any 500 ppm sulfur diesel fuel that is produced, however, must be appropriately designated and labeled for tracking purposes throughout the distribution system, and cannot be sold for use in 2011 and later model year nonroad engines. From June 1, 2012, when the 15 ppm sulfur standard for LM diesel fuel becomes effective, through May 31, 2014, refiners/importers may use either high sulfur credits or 500 ppm sulfur credits to continue producing/importing 500 ppm sulfur NRLM diesel fuel. All credits expire after May 31, 2014. Hence, beginning June 1, 2014, all NRLM diesel fuel produced by refiners or imported in the U.S. will be subject to the 15 ppm sulfur standard, except LM diesel fuel produced by transmix processors from transmix can continue to meet the 500 ppm sulfur limit.

We proposed that all credits would expire May 31, 2012, however we are finalizing an expiration date of May 31, 2014 based on the comments we received. The additional two years that we are now allowing for credit use (1) will provide a longer period for refiners to sell off-specification fuel instead of having to reprocess it, (2) is an environmentally neutral change to the overall program, and (3) is now consistent with the end-date for small refiner flexibility.

While credits can be generated and traded nationwide, they are restricted from use in certain parts of the country under the provisions of this final rule. As discussed in section IV.D, we are avoiding the burden to terminals of adding marker to heating oil in those areas of the country where demand for heating oil is expected to continue to remain high after today's final rule. The NRLM diesel fuel sulfur standards will be enforced based on sulfur level in these areas, not through the refinery designation and marker provisions. Consequently, in the area defined in section IV.D comprising most of the Northeast and Mid-Atlantic region of the country, as well as in the State of Alaska, many of the fuel program's flexibilities, including refiners' ability to use credits, are not allowed. Refiners and importers may not use credits to produce or import diesel fuel with a sulfur content greater than 500 ppm beginning June 1, 2007 or 15 ppm beginning June 1, 2010, for sale or distribution in this Northeast/Mid-Atlantic area or the State of Alaska. However, credits generated in these areas can be sold to other refiners and/or importers for use outside these areas.

B. Hardship Relief Provisions for Qualifying Refiners

As in our gasoline sulfur and highway diesel fuel sulfur programs, today's program contains the following hardship relief provisions to provide regulatory flexibility to challenged refiners:

- Small refiner hardship for qualifying small refiners;
- General hardship for any refiner experiencing either—

(1) Extreme unforeseen circumstances such as natural disaster or acts of God; or

(2) Extreme hardship circumstances such as financial or technical hardship.

Similar provisions have proved invaluable for some refiners in the recent implementation of the gasoline sulfur standards, as well as for refiners' planning for the highway diesel standards. The details of these provisions are discussed below.

1. Hardship Provisions for Qualifying Small Refiners

As in previous fuel rulemakings, our justification for including provisions specific to small refiners is that, in general, small refiners generally have a degree of hardship in complying with the standards compared to other refiners. In the NPRM, we proposed flexibilities/transition provisions, or "hardship provisions" (these terms are equivalent), for small refiners. We are adopting the provisions that were proposed for small refiners virtually unchanged, and including similar provisions for the treatment of locomotive and marine fuel.

a. Regulatory Process and Justification for Small Refiner Relief

In developing our NRLM diesel fuel sulfur program, we evaluated the environmental need as well as the technical and financial ability of refiners to meet the 500 and 15 ppm sulfur standards as expeditiously as possible. We believe it is feasible and necessary for the vast majority of the program to be implemented in the established time frame to achieve the air quality benefits as soon as possible. Based on information available from small refiners and others, we believe that refiners classified as small generally face unique circumstances with regard to compliance with environmental programs, compared to larger refiners. Consequently, as discussed below, we are finalizing several special provisions for refiners that qualify as "small refiners" to reduce the disproportionate burden that today's program will have on them.

Small refiners generally lack the resources that are available to large refining companies, including those large companies that own small-capacity refineries, to raise capital for investing in desulfurization equipment, such as shifting of internal funds, securing of financing, or selling of assets. Small refiners are also likely to have more difficulty in competing for engineering and construction resources needed for the installation of the desulfurization equipment which will likely be required to meet the standards finalized in this action.

Because small refiners are more likely to face adverse circumstances with regard to regulatory compliance than larger refiners, we are finalizing interim provisions that will provide additional time for refineries owned by small refiners to meet the sulfur standards. This approach will allow the overall program to begin as early as possible, avoiding the need for delay in order to address the ability of small refiners to comply.

i. Regulatory Flexibility Process for Small Refiners

As explained in the discussion of our compliance with the Regulatory Flexibility Act (RFA) in section X.C of this preamble, and in the Final Regulatory Flexibility Analysis in chapter 11 of the RIA, we considered the impacts of today's regulations on small businesses. Most of our analysis of small business impacts was performed as part of the Small Business Advocacy Review (SBAR) Panel convened by EPA, pursuant to the RFA as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The Panel's final report is available in the rulemaking public docket (Docket A–2001–28, Document No. II–A–172).

For the SBREFA process, EPA conducted outreach, fact-finding, and analysis of the potential impacts of the proposed nonroad regulations on small businesses. Based on these discussions and analyses by all panel members, the Panel concluded that small refiners in general would likely experience a significant and disproportionate financial burden in reaching the objectives of the proposed nonroad diesel fuel sulfur program.

One indication of the disproportionate burden on small refiners is the relatively high cost per gallon projected for producing NRLM diesel fuel under today's program. Refinery modeling of refineries owned by refiners likely to qualify as small refiners, and of refineries owned by other non-small refiners, indicates significantly higher refining costs for small refiners. Specifically, we project that without special provisions, refining costs for small refiners on average would be about two cents per gallon higher than for other refiners in the same PADD to meet the 15 ppm sulfur standard.

The Panel also noted that the burden imposed on small refiners by the proposed sulfur standards may vary from refiner to refiner. Thus, the Panel recommended more than one type of burden mitigation so that most, if not all, small refiners could benefit. We considered the issues raised during the SBREFA process, and discussed them in the NPRM, and have decided to finalize each of the provisions recommended by the Panel. A discussion of the comments we received regarding small refiners and terminal operators, and our responses to those comments, can be found in section X.C of this preamble, and also the Summary and Analysis of Comments.

ii. Rationale for Small Refiner Regulatory Flexibility Provisions

Generally, we structured the small refiner provisions to reduce the burden on small refiners while expeditiously achieving air quality benefits and ensuring that the availability of 15 ppm sulfur NR diesel fuel will coincide with the introduction of 2011 model year nonroad diesel engines and equipment. We believe the special provisions for small refiners are necessary and appropriate for several reasons.

First, the compliance schedule for today's program, combined with special relief provisions for small refiners, will achieve the air quality benefits of the program as soon as possible, while helping to ensure that small refiners will have adequate time to raise capital for new or upgraded fuel desulfurization equipment. Most small refiners have limited additional sources of income beyond refinery earnings for financing and typically do not have the financial backing that larger and generally more integrated companies have. Therefore, additional time to accumulate capital internally or to secure capital financing from lenders can be central to their ability to comply.

Second, we recognize that while the sulfur levels in today's program can be achieved using conventional refining technologies, new technologies are also being developed that may reduce the capital and/or operating costs of sulfur removal. Thus, we believe that providing small refiners some additional time to allow for new technologies to be proven out by other refiners will have the added benefit of reducing the risks faced by small refiners. The added time will likely enable small refiners to benefit from the lower costs of these improvements in desulfurization technology (*e.g.*, better catalyst technology or lower-pressure hydrotreater technology). This will help to offset the disproportionate financial burden that may be imposed upon small refiners.

Finally, providing small refiners more time to comply will spread out the availability of engineering and construction resources. Most refiners will need to install additional processing equipment to meet the NRLM diesel fuel sulfur requirements. We anticipate that there may be significant competition for technology services, engineering resources, and construction management and labor. In addition, as has been the experience in gasoline sulfur control, vendors will be more likely to contract their services with the larger refiners first, as their projects will offer larger profits for the vendors. Temporarily delaying compliance for small refiners will spread out the demand for these resources and may help reduce cost premiums for everyone caused by limited engineering and construction supply.

We discuss below the provisions that we are finalizing to minimize the degree of hardship imposed upon small refiners by this program. With these provisions we are confident in going forward with the 500 ppm sulfur standard for NRLM diesel fuel in 2007 and the 15 ppm sulfur standard for NR diesel fuel in 2010 and for LM diesel fuel in 2012, for the rest of the industry. The provisions for small refiners will allow these refiners to continue to produce higher sulfur NRLM fuel until June 1, 2010, and similarly, will allow for the production of 500 ppm nonroad NRLM fuel until June 1, 2014. Without small refiner relief, we would have to consider delaying the overall program until the burden of the program on many small refiners was diminished, which would delay the air quality benefits of the overall program. By providing temporary relief to small refiners, we are able to adopt a program that expeditiously reduces NRLM diesel fuel sulfur levels in a feasible manner for the industry as a whole.

The four-year leadtime from which begins in 2010 for small refiners for locomotive and marine diesel fuel is identical to the relief that was supported by small refiners for nonroad diesel fuel. We believe that this relief is necessary and adequate to reduce the burden on small entities while still achieving our air quality goals. Small refineries vary considerably in their markets for NRLM diesel fuels. Consequently, the proposal to control nonroad diesel fuel to 15 ppm sulfur impacted small refiners with significant nonroad market shares, but left those with significant locomotive and marine market shares relatively untouched. With control of all NRLM diesel fuel to 15 ppm sulfur in this final rule, all small refiners of NRLM diesel fuel will face similar challenges, and therefore the same four year lead time from 2010 proposed for those small refiners impacted by nonroad fuel control alone is also appropriate when the standards are expanded to all NRLM. In essence, while more small refiners face the challenge of desulfurizing all of their diesel fuel to the 15 ppm sulfur standard, the magnitude of this challenge is not any greater. Furthermore, providing additional relief (beyond 2014) to small refiners would undermine the program by further delaying air quality benefits. The 2014 deadline for all small refiner diesel fuel to 15 ppm sulfur will also simplify the fuel program and it will allow small refiners the ability to coordinate their plans to reduce the sulfur content of all off-highway diesel fuel at the same time.

iii. Impact of Small Refiner Options on Program Emissions Benefits

Small refiners that choose to delay the NRLM diesel fuel sulfur requirements will also delay to some extent the emission reductions that would otherwise have been achieved. However, for several reasons, the overall impact of these postponed emission reductions will be small. First, small refiners represent only a fraction of national non-highway diesel production. Today, refiners that we expect to qualify as small refiners represent only about six percent of all high-sulfur diesel production. Second, the delayed compliance provisions described below will affect only engines without new emission controls. During the program's first step to 500 ppm sulfur NRLM diesel fuel, small refiner NRLM diesel fuel could be well above 500 ppm sulfur, but the new advanced engine controls will not yet be required. During the second step to 15 ppm sulfur NRLM diesel fuel, equipment with the new controls will be entering the market, but use of the 500 ppm small refiner fuel will be restricted to older engines without the new controls. There will be some loss of sulfate PM control in the older engines that operate on higher sulfur small refiner fuel, but no effect on the major emission reductions that the new engine standards will achieve starting in 2011. Finally, because small diesel refiners are generally dispersed geographically across the country, the limited loss of sulfate PM control will also be dispersed.

One option for small refiner relief will allow a modest 20 percent relaxation in the gasoline sulfur interim standards for small refiners that produce all of their NRLM diesel fuel at 15 ppm sulfur by June 1, 2006. To the extent that small refiners elect this option, a small loss of emission control from Tier 2 gasoline vehicles that use the higher sulfur gasoline could occur. We believe that such a loss of control will be very small. Very few small refiners will be in a position to use this provision. Further, the relatively small production of gasoline with slightly higher sulfur levels should have no measurable impact on the emissions of new Tier 2 vehicles, even if the likely "blending down" of sulfur levels does not occur as this fuel mixed with lower sulfur fuel during distribution. This provision will also maintain the maximum 450 ppm gasoline sulfur per-gallon cap standard in all cases, providing a reasonable sulfur ceiling for any small refiners using this provision.

b. Small Refiner Definition for Purposes of the Hardship Provisions

The definition of small refiner under the NRLM diesel program is similar to the definitions under the Tier 2/ Gasoline Sulfur and Highway Diesel rules. Under the NRLM program, a small refiner must demonstrate that it meets the following criteria:

- Produced NRLM diesel from crude;
- No more than 1,500 employees corporate-wide, based on the average number of employees for all pay periods from January 1, 2002 to January 1, 2003; and,
- A corporate crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2002.

As with the earlier fuel sulfur programs, the effective dates for the determination of employee count and for calculation of the crude capacity represent the most recent complete year prior to the issuing of the proposed rulemaking (2002, in this case).

In determining its total number of employees and crude oil capacity, a refiner must include the number of employees and crude oil capacity of any subsidiary companies, any parent company and subsidiaries of the parent company, and any joint venture partners. We define a subsidiary of a company to mean any subsidiary in which the company has a 50 percent or greater ownership interest. However, refiners owned and controlled by an Alaska Regional or Village Corporation organized under the Alaska Native Claims Settlement Act (43 U.S.C. 1626), are also eligible for small refiner status, based only on the refiner's employees and crude oil capacity. Such an exclusion is consistent with our desire to grant regulatory relief to that part of the industry that is the most challenged with respect to regulatory compliance. We believe that very few refiners, probably only one, will qualify under this provision. We are also incorporating this exclusion into the small refiner provisions of the highway diesel and gasoline sulfur rules, which did not address this issue.

As under the gasoline sulfur and highway diesel fuel rules, refiners that either acquire or restart a refinery in the future may be eligible for small refiner status under the NRLM program. Specifically, a refiner that either acquires or restarts a refinery that was shut down or non-operational between January 1, 2002 and January 1, 2003 may apply for small refiner status. In such cases, we will judge eligibility under the employment and crude oil capacity criteria based on the most recent 12 consecutive months of data unless we conclude from the data provided by the refiner that another period of time is more appropriate. Companies with refineries built after January 1, 2002 are not eligible for the small refiner provisions. Similarly, entities that do not own or operate a refinery are not eligible to apply for small refiner status.

c. Provisions for Small Refiners

We are finalizing several provisions intended to reduce the regulatory burden of today's program on small refiners as well as to encourage their early compliance whenever possible. As described below, these small refiner relief options consist of additional time for compliance and, for small refiners that choose to comply earlier than required, the option of either generating diesel fuel sulfur credits or receiving a limited relaxation of their gasoline sulfur standards.

i. NRLM Delay Option

First, we are finalizing an option that allows small refiners to postpone their compliance with the NRLM diesel fuel sulfur standards. The delayed compliance schedule for small refiners is intended to compensate for the relatively higher compliance burdens on these refiners. It is not intended as an opportunity for those refiners to greatly expand their production of uncontrolled diesel fuel (2007–2010) or 500 ppm sulfur diesel fuel (2010–2014). To help ensure that any significant expansion of refining capacity that a small refiner might undertake in the future is accompanied by an expansion of desulfurization capacity, small refiners producing higher sulfur fuel must limit their production to baseline volume levels. Specifically, during the first step of today's diesel fuel program to 500 ppm sulfur, from June 1, 2007 through May 31, 2010, a small refiner may at any or all of its refineries produce uncontrolled NRLM diesel fuel up to the 2003 through 2005 non-highway baseline volume for the refinery(s). Any diesel fuel produced over the baseline volume will be subject to the 500 ppm sulfur standard applying to other refiners. Similarly, from June 1, 2010 through May 31, 2014, a small refiner may produce at any or all of its refineries NRLM diesel fuel subject to the 500 ppm sulfur standard at a volume equal to or less than the refineries' 2006–2008 non-highway baseline volumes. LM fuel produced to the 500 ppm standard during 2010 to 2012 would be counted towards meeting this baseline volume. NRLM fuel produced in excess of the baseline volume will be subject to the 15 ppm sulfur NRLM diesel fuel standard. The baseline for 2003–2005 will be determined by subtracting the refinery's highway volume from its total highway and heating oil volume production. The baseline for 2006–2008 will be determined based upon the volume of the refinery's NRLM fuel designations discussed in section IV.D.

As discussed in section IV.D, the costs to the distribution system to mark heating oil in areas of PADD 1 with high heating oil demand to distinguish it from small refiner or credit-using high sulfur NRLM made this option undesirable in these areas. Based on our review of anticipated small refiner situations, this portion of PADD 1 appears unlikely to provide a meaningful market for small refiners seeking this option. Therefore, in this part of the country it imposed costs without providing the intended benefit. Consequently, while this option was proposed to be available nationwide, we are not finalizing it for a portion of PADD 1. This change from the proposal should have no meaningful impact on small refiners' flexibility, but will reduce the costs for fuel distributors.

Since new engines with sulfur sensitive emission controls will begin to become widespread beginning in 2011, small refiner fuel can only be sold for use in pre-2011 nonroad equipment or in locomotives or marine engines during this time. Section IV.D below discusses the requirements for designating and tracking the production of 500 ppm sulfur NRLM diesel fuel produced by small refiners during this period.

The following table illustrates the small refiner NRLM diesel fuel sulfur standards as compared to the standards for the base NRLM diesel fuel program. As previously stated, small refiners will receive additional lead time, compared to non-small refiners for 15 ppm sulfur locomotive and marine diesel fuel. This lead time is identical to that which had been proposed for 15 ppm sulfur nonroad diesel fuel. This will ensure that emission benefits of ultra low sulfur diesel fuel are achieved as soon as possible, and should not significantly change the nature or magnitude of the burden on affected small refiners.

TABLE IV–4.—SMALL REFINER NRLM DIESEL FUEL SULFUR STANDARDS, PPM [a]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015+
Non-Small Refiners–NR fuel	....	500	500	500	15	15	15	15	15	15
Non-Small Refiners–LM fuel	....	500	500	500	500	500	15	15	15	15
Small Refiners–NR diesel fuel	....	....	....	....	500	500	500	500	15	15
Small Refiners–LM diesel fuel	....	....	....	....	500	500	500	500	15	15

Notes: [a] New standards will take effect on June 1 of the applicable year.

ii. NRLM Credit Option

Some small refiners have indicated that, for a variety of reasons, they might need to produce fuel meeting the NRLM diesel fuel sulfur standards earlier than required under the small refiner program described above. For some small refiners, the distribution system might limit the number of grades of diesel fuel that will be carried. Others might find it economically advantageous to make 500 ppm or 15 ppm sulfur NRLM diesel fuel earlier than required to prevent losing market share. At least one small refiner has indicated that it might decide to desulfurize its NRLM pool at the same time as it desulfurizes its highway diesel fuel, in June 2006, due to limitations in its distribution system and to take advantage of economies of scale.

The NRLM Credit option allows small refiners to participate in the NRLM diesel fuel sulfur credit banking and trading program discussed earlier in this section. Under this option, a small refiner may generate diesel fuel sulfur credits by producing any volume of 500 ppm sulfur NRLM diesel fuel from crude oil prior to from June 1, 2006 through May 31, 2010, and by producing any volume from crude oil of 15 ppm sulfur NRLM diesel fuel from June 1, 2010 through December 31, 2013. The specifics of the credit program are described in section IV.A.4, including how the program applies to small refiners. Generating and selling credits could provide small refiners with funds to help defray the costs of early NRLM compliance.

iii. NRLM/Gasoline Compliance Option

The NRLM/Gasoline Compliance option is available to small refiners that produce greater than 95 percent of their NRLM diesel fuel at the 15 ppm sulfur standard by June 1, 2006 and elect not to use the provision described above to earn NRLM diesel fuel sulfur credits for this early compliance. Refiners choosing this option will receive a modest revision in their small refiner interim gasoline sulfur standards, beginning January 1, 2004. Specifically, the applicable small refiner annual average and per-gallon cap gasoline sulfur standards will be increased by 20 percent for the duration of the interim program. The interim program is through either 2007 or 2010, depending on whether the refiner extended the duration of its interim gasoline sulfur standards by producing 15 ppm sulfur highway diesel fuel by June 1, 2006, as provided under 40 CFR 80.552(c). In no case may the per-gallon gasoline sulfur cap exceed 450 ppm, the highest level allowed under the gasoline sulfur program.

We believe it is very important to link any relaxation of a small refiner's interim gasoline sulfur standards with the environmental benefit of early desulfurization of a significant volume of NRLM diesel fuel. As such, a small refiner choosing to use this option must produce a minimum volume of NRLM diesel fuel at the 15 ppm sulfur standard by June 1, 2006. Each participating small refiner must produce a volume of 15 ppm sulfur fuel that is at least 85 percent of the annual average volume of non-highway diesel fuel it produced from 2003–2005. If the refiner began to produce gasoline in 2004 at the higher interim standard under this provision but then either fails to meet the 15 ppm sulfur standard for its NRLM diesel fuel by June 1, 2006 or fails to meet the 85 percent minimum volume requirement, the original small refiner interim gasoline sulfur standard applicable to that refiner will automatically apply retroactively to 2004. In addition, the refiner must compensate for the higher gasoline sulfur levels by purchasing gasoline sulfur credits or producing an equivalent volume of gasoline below the required sulfur levels. Under this option, a small refiner could in effect shift some funds from its gasoline sulfur program to accelerate desulfurization of

NRLM diesel fuel. While there would be a small potential loss of emission reduction under the gasoline sulfur program from fuel produced by the very few small refiners that we believe would choose this second option, there are also environmental benefits gained from the production of 15 ppm sulfur diesel fuel earlier than otherwise required.

iv. Relationship of the Options to Each Other

A small refiner may choose to use the NRLM Delay option, the NRLM Credit option or both in combination, since it has no requirement to produce 500 ppm sulfur NRLM diesel fuel before June 1, 2010, or 15 ppm sulfur NRLM diesel fuel before June 1, 2014. Thus any fuel that it produces from crude at or below the sulfur standards earlier than required will qualify for generating credits.

On the other hand, the NRLM/Gasoline Compliance option may not be used in combination with either the NRLM Delay option or the NRLM Credit option, since a small refiner must produce at least 85 percent of its NRLM diesel fuel at the 15 ppm sulfur standard under the NRLM/Gasoline Compliance option.

d. How Do Refiners Apply for Small Refiner Status?

A refiner applying for small refiner status must provide the Agency with several types of information by December 31, 2004. The detailed application requirements are summarized in section V.F.2 below. In general, a potential small refiner must own the refinery/refineries in question and must provide the following information for the parent company and all subsidiaries at all locations: (1) The average number of employees for all pay periods from January 1, 2002 through January 1, 2003; (2) the total corporate crude oil capacity, which must be a positive number; and (3) an indication of which small refiner option the refiner intends to use (see section IV.B.1.c above). As with applications for relief under other fuel programs, applications for small refiner status under this rule that are later found to contain false or inaccurate information will be void *ab initio*.

e. The Effect of Financial and Other Transactions on Small Refiner Status and Small Refiner Relief Provisions

Since the gasoline sulfur and highway diesel fuel sulfur programs were finalized, several refiners have raised concerns about how various financial and other transactions could affect implementation of the small refiner fuel sulfur provisions. These types of transactions typically involve refiners with approved small refiner status that are involved in potential or actual sales of the small refiner's refinery, or involve the small refiner merging with another refiner or purchasing another refinery (or other non-refining asset). We believe that these concerns are also relevant to the small refiner provisions described below for the NRLM diesel fuel sulfur program.

i. Large Refiner Purchasing a Small Refiner's Refinery

The first type of transaction involves a "non-small" refiner that wishes to purchase a refinery owned by an approved small refiner. In some cases, the small refiner may not have completed or even begun refinery upgrades to meet the long-term fuel sulfur standards if it was using an interim small refiner compliance provision. Under the gasoline sulfur and highway diesel fuel sulfur programs, once such a purchase transaction is completed, the "non-small" buyer does not have the benefit of the small refiner relief provisions that had applied to the previous owner.

The purchasing refiner would have to perform the necessary upgrades on the acquired refinery for it to meet the "non-small" sulfur standards. As the gasoline sulfur and highway diesel fuel sulfur provisions existed prior to today's action, such a refiner would be left with very little or, in the case of the gasoline sulfur program which has already begun, no lead time to bring the refinery into compliance. The refiners that have raised this issue have claimed that refiners in this situation would not be able to immediately comply with the "non-small refiner" standards upon acquisition of the new refinery. These refiners claim that this could prevent them from purchasing a refinery from a small refiner and, as a result, this would severely limit the ability of small refiners to sell such an asset. The refiners that raised this issue requested additional lead time before the non-small refiner sulfur standards take effect.

We received comments on this issue from two refiners. Both refiners commented that lead time for refiners losing their small refiner status should only be allowed for the case where a small refiner merges with, or acquires, another small refiner. Neither refiner supports allowing additional lead time for a large refiner that merges with or acquires a small refiner. In addition, these refiners also commented that it would be inappropriate to allow a small refiner that receives this lead time to be able to generate credits for "early" production of lower sulfur diesels during this two-year period.

Nevertheless, we continue to believe these lead-time concerns are valid. Failure to address them could lead to unnecessary disruption to the diesel fuel market. Therefore, we are adopting a provision to provide an appropriate period of lead time for compliance with the NRLM diesel fuel sulfur requirements for situations in which a refiner purchases any refinery owned by a small refiner, whether by purchase of the refinery or purchase of the small refiner entity. Refiners that acquire a refinery from an approved small refiner will be provided 30 additional months from the date of the completion of the purchase transaction (but no later than June 1, 2010 for 500 ppm NRLM fuel and June 1, 2014 for 15 ppm NRLM fuel). During this interim period, production at the newly-acquired refinery may remain at the interim sulfur levels that applied to that refinery for the previous small refiner owner under the small refiner options discussed below. At the end of this period, the refiner must comply with the "non-small refinery" sulfur standards.

We received comments suggesting that the proposed 24 months of additional lead time would not be adequate, and further, discussions with several refiners indicated that in most cases, 24 months would be inadequate. As discussed in section IV.F, we project a range of 27–39 months is needed to design and construct a diesel hydrotreater. Therefore, in order to allow a reasonable opportunity for complying, we are finalizing the provision that 30 months of additional lead time will be afforded. Thirty months should in most cases be sufficient for the new refiner-owner to accomplish the necessary engineering, permitting, construction, and start-up of the necessary desulfurization equipment. However, if there are instances where the technical characteristics of its planned desulfurization project will require additional lead time, we have included provisions for the refiner to apply for up to six months of additional time and for EPA to consider such requests on a case-by-case basis. Such an application must be based on the technical factors supporting the need for more time and should include detailed technical information and projected schedules for engineering, permitting, construction, and startup. Based on information provided in such an application and other relevant information, EPA will decide whether additional time is technically necessary and, if so, how much additional time is appropriate. However, we anticipate that in most cases 30 months will be sufficient, since developing plans for compliance should be expected to be a part of any purchase decision.

All existing small refiner provisions and restrictions, as described below, will also remain in place for that refinery during the 30 months of additional lead time and any further lead time approved by EPA for the purchasing refiner; including the per-refinery volume limitation on the amount of NRLM diesel that may be produced at the small refiner standards. Furthermore, since the purpose of this grace period is solely to provide time to bring the refinery into compliance with the NRLM standards, refiners will not be allowed to generate credits for early compliance during this 30 month period. There will be no adverse environmental impact of this provision, since the small refiner would have already been provided this same relief prior to the purchase and this provision is no more generous.

ii. Small Refiner Losing Its Small Refiner Status Due To Merger or Acquisition

Another type of transaction involves a refiner with approved small refiner status that later loses its small refiner status because it exceeds the small refiner criteria. Under the gasoline sulfur and highway diesel fuel sulfur regulations, an approved small refiner that exceeds 1,500 employees due to merger or acquisition will lose its small refiner status. We also intended for refiners that exceeded the 155,000 barrel per calendar day crude capacity limit due to merger or acquisition to lose its small refiner status and in this rule we are amending the regulations to reflect that criterion as well. This includes exceedances of the employee or crude capacity criteria caused by acquisitions of assets such as plant and equipment, as well as acquisitions of business entities.

Our intent in the gasoline and highway diesel fuel sulfur programs, as well as the NRLM diesel fuel sulfur program, has been and continues to be, limiting the small refiner relief provisions to a small subset of refiners that are challenged, as discussed above. At the same time, it is also our intent to avoid stifling normal business growth. Therefore, the regulations we are adopting today will disqualify a refiner from small refiner status if it exceeds the small refiner criteria through its involvement in transactions such as being acquired by or merging with another entity, through the small refiner itself purchasing another entity or assets from another entity, or when it ceases to process crude oil. However, an approved small refiner who exceeds the employee or crude oil capacity criteria without merger or acquisition, may retain its small refiner status for the purposes of the complying with the NRLM diesel fuel standards. Furthermore, in the sole case of a merger between two approved small refiners we will allow such refiners to retain their small refiner status for purposes of complying with the NRLM diesel fuel program. Commenters explained that additional financial resources would not typically be provided in the case of a merger between small refiners. In light of these comments, we believe the justification for continued small refiner relief for the merged entity is valid. Small refiner status for the two entities of the merger will not be affected, hence the original compliance plans of the two refiners should not be impacted. Moreover, no environmental detriment will result from the two small refiners maintaining their small refiner status within the merged entity as they would have likely maintained their small refiner status had the merger not occurred.

Consistent with our intent in the gasoline sulfur and highway diesel fuel sulfur programs to limit the use of the small refiner hardship provisions, we also intended in the gasoline sulfur and highway diesel fuel sulfur programs that an exceedance of corporate crude oil capacity limit of 155,000 bpcd, due to merger or acquisition, would be grounds for disqualifying a refiner's small refiner status. However, we inadvertently failed to include this second criterion as grounds for disqualification in the regulations. In today's action, we are resolving this error by including the crude capacity limit, along with the employee limit for both the gasoline sulfur and highway diesel fuel sulfur programs, effective January 1, 2004. Thus, a refiner exceeding either criterion due to merger or acquisition will lose its small refiner status. The exception to this would be in the case of merger only between two small refiners. We received comments supporting the allowance of additional lead time for small refiners that lose their small refiner status through a merger with, or acquisition of, another small refiner.

We recognize that a small refiner that loses its small refiner status because of a merger with, or acquisition of, a non-small refiner would face the same type of lead time concerns in complying with the non-small refiner standards as a non-small refiner that acquired a small refiner's refinery would. Therefore, the additional lead time described above for non-small refiners purchasing a small refiner's refinery will also apply to this situation. Thus, this 30 month lead time will apply to all of the refineries, existing or newly-purchased, that had previously been subject to the small refiner program, but would not apply to a newly-purchased refinery that is subject to the non-small refiner standards. Again, there would be no adverse environmental impact because of the pre-existing relief provisions that applied to the newly-purchased small refiner.

The issues discussed in this section apply equally to the gasoline sulfur and highway diesel fuel sulfur programs. Thus, we are also adopting the same provisions relating to additional lead time in cases of certain financial, or other, transactions for the small refiner programs in the earlier fuel sulfur programs.

In the proposal for today's final rule, we invited comment on several other related provisions that were considered during the development of this rulemaking:

(1) Instead of merely allowing small refiners a grace period to come into compliance if they lose their small refiner status, we also asked for comment on whether or not such a small refiner should instead be allowed to "grandfather" the small refiner relief provisions for its existing refinery or refineries. We did not receive any specific comments on this issue and we are not finalizing this provision in today's action.

(2) Regarding small refiners that exceed the small refiner criteria due to the purchase of a non-small refiner's refinery, we requested comment on whether or not the proposed additional lead time should apply to the purchased refinery. We also requested comment on whether or not the refiner should be required to meet the non-small refiner standards on schedule at the purchased refinery, since the previous owner could be assumed to have anticipated the new standards and taken steps to accomplish this prior to the purchase. One refiner commented that merger acquisition flexibility for refineries that lose their small refiner status should be limited to instances where a small refiner merges with another small refiner. They believed that any small refiner that loses its small refiner status due to an acquisition of a non-small refiner's refinery should not be eligible for hardship relief. Similarly, another refiner commented that a refiner should not retain small refiner status if it has

the financial resources to acquire additional refineries that increase corporate-wide crude processing above 155,000 bpd. We are not adopting any flexibility for the purchased refinery in this situation (except in the case of a merger between two small refiners, as discussed above).

f. Provisions for Approved Gasoline and Highway Diesel Fuel Small Refiners That Do Not Qualify for Small Refiner Status Under Today's Program

Some refiners that have approved small refiner status under the gasoline sulfur and highway diesel fuel programs may not qualify for small refiner status under today's program if they have grown through normal business operations and now exceed the qualification criteria for NRLM small refiner status. One refiner commented on the lack of a "grandfather" provision in the nonroad proposal that would automatically continue small refiner status to refiners already approved as small refiners under the gasoline and highway diesel fuel sulfur programs. Without such a provision some refiners could be approved small refiners under the gasoline sulfur and highway diesel fuel sulfur programs (because they grew through normal business expansions and not through merger or acquisition) but would not qualify under the NRLM program because they now exceed the criteria. As a consequence, the commenter argued that in some cases benefits afforded to such small refiners under the gasoline and highway diesel fuel sulfur programs could be negated. Specifically, under the highway diesel rule they were allowed until 2010 before needing to have diesel fuel hydrotreating capacity. Under the nonroad rule, they would have to do so in 2007. Since it would only make sense to invest for adequate 15 ppm capacity when they do invest, the nonroad standards essentially would require them to invest to bring all highway and nonroad diesel to 15 ppm sulfur in 2007, eliminating the flexibility granted them in the highway rule. Furthermore, the refiners' clean fuel projects for low sulfur gasoline, highway diesel fuel, and NRLM diesel fuel could no longer be staggered. In fact, small refiners in such situations would be required to make investments for compliance with all three fuel programs in the same three to four year period, if not virtually all at once.

We believe that a refiner who no longer meets the criteria for small refiner status, since it has successfully grown through normal business operations, does not face the same level of hardship described earlier in this section. We do not intend for the NRLM program to undermine the benefits afforded to small refiners under the gasoline and highway diesel fuel sulfur programs, as described in the comments. At the same time, however, we want to preserve small refiner status under today's program only for those businesses that meet the criteria described above. Under the nonroad proposal, a refiner with approved small refiner status under the highway diesel fuel program but not the NRLM program would be required to produce 500 ppm sulfur NRLM diesel fuel in 2007 and both 15 ppm sulfur highway and NR diesel fuel in 2010. Under today's final program, such a refiner may instead skip the 2007 500 ppm interim sulfur standard for its NRLM diesel fuel, and meet the 15 ppm sulfur standard for both its highway and NR diesel fuel in 2010 and LM diesel fuel in 2012. Such an approach will maintain the refiner's flexibility under the highway program by allowing it to delay diesel hydrotreating investment until 2010, while limiting its flexibility under the nonroad diesel program.

g. Additional Provisions and Program Elements

To reduce the burden on all refiners (including small refiners), we have chosen to finalize the designate and track approach, rather than the baseline approach. Discussions with parties in all parts of the distribution system led us to believe that this is the preferred approach, as tracking is currently done by parties throughout the distribution system. We are also finalizing provisions to simplify the segregation, marking, and dyeing requirements. In addition, we are finalizing provisions to alleviate the concern raised by small terminal operators regarding the heating oil marker. Terminals in parts of PADD 1 (Northeast/Mid-Atlantic Area) will not have to add the marker to home heating oil. Therefore we expect that no terminals inside of the Northeast/Mid-Atlantic Area will need to install injection equipment. These provisions are discussed in greater detail in section IV.D, below.

2. General Hardship Provisions

a. Temporary Waivers From NRLM Diesel Fuel Sulfur Requirements in Extreme Unforseen Circumstances

We are finalizing a provision which, at our discretion, will permit any domestic or foreign refiner to seek a temporary relief from the NRLM diesel fuel sulfur standards under certain rare circumstances. This waiver provision is similar to provisions in the reformulated gasoline, low sulfur gasoline, and highway diesel fuel sulfur regulations. It is intended to provide refiners short-term relief due to unanticipated circumstances, such as a refinery fire or a natural disaster, that cannot be reasonably foreseen now or in the near future.

Under this provision, a refiner may seek a waiver to distribute NRLM diesel fuel that does not meet the applicable 500 ppm or 15 ppm sulfur standards for a brief time period. An approved waiver of this type could, for example, allow a refiner to produce and distribute diesel fuel with higher than allowed sulfur levels, so long as the other conditions described below were met. Such a request must be based on the refiner's inability to produce complying NRLM diesel fuel because of extreme and unusual circumstances outside the refiner's control that could not have been avoided through the exercise of due diligence. The request must also show that other avenues for mitigating the problem, such as the purchase of credits to be used toward compliance, had been pursued yet were insufficient. As with other types of regulatory relief established in this rule, this type of temporary waiver will have to be designed to prevent fuel exceeding the 15 ppm sulfur standard from being used in 2011 and later model year nonroad engines.

The conditions for obtaining a NRLM diesel fuel sulfur waiver are similar to those under the RFG, gasoline sulfur, and highway diesel fuel sulfur regulations. These conditions are necessary and appropriate to ensure that any waivers that are granted are limited in scope, and that refiners do not gain economic benefits from a waiver. Therefore, refiners seeking a waiver will be required to show that the waiver is in the best public interest and that they: (1) Were not able to avoid the nonconformity; (2) will make up the air quality detriment associated with the waiver; (3) will make up any economic benefit from the waiver; and (4) will meet the applicable diesel fuel sulfur standards as expeditiously as possible.

b. Temporary Relief Based on Extreme Hardship Circumstances

In addition to the provision for short-term relief under extreme unforseen circumstances, we are finalizing a provision for relief based on extreme hardship circumstances such as circumstances that impose extreme hardship and significantly affect a refiners ability to comply with the program requirements by the applicable dates. This provision is also very similar to those established under the gasoline sulfur and highway diesel fuel sulfur programs. Under the gasoline sulfur program, we have granted relief in the form of individual compliance plans to five refiners. Under the highway diesel program, we have approved two. Each plan was designed for the specific situation of that refiner. In all cases, the companies would have experienced severe hardship if temporary relief had not been granted. Moreover, some refineries were at a high risk of shutting down without the relief.

In developing today's program, as under our other fuel programs, we considered whether any refiners would face particular difficulty in complying with the standards in the lead time provided. As described earlier in this section, we concluded that, in general, small refiners would experience more difficulty in complying with the standards on time because they have less ability to raise the capital necessary for refinery investments, face proportionately higher costs because of poorer economies of scale, and are less able to successfully compete for limited engineering and construction resources. However, it is possible that other refiners that are not small refiners may also face particular difficulty in complying on time with the sulfur standards required under today's program. Therefore, we are including in this rulemaking a provision which allows us, at our discretion, to grant temporary waivers from the NRLM diesel fuel sulfur standards based on a showing of extreme hardship circumstances.

The extreme hardship provision allows any domestic or foreign refiner to request relief from the sulfur standards based on a showing of unusual circumstances that result in extreme hardship and significantly affect a refiner's ability to comply with either the 500 ppm or 15 ppm sulfur NRLM diesel fuel standards by either June 1, 2007, June 1, 2010, or June 1, 2012, respectively. The Agency will evaluate each application on a case-by-case basis, considering the factors described below. Approved hardship applications may include compliance plans with relief similar to the provisions for small refiners, which are described in detail above in section IV.B.1.c. Depending on the refiner's specific situation, such approved delays in meeting the sulfur requirements may be more stringent than those allowed for small refiners, but will not likely be less stringent. Given such an approval, we expect to impose appropriate conditions to: (1) Assure the refiner is making its best effort; and (2) minimize any loss of emissions benefits from the program. As with other relief provisions established in this rule, any waiver under this provision will be designed to prevent fuel exceeding the 15 ppm sulfur standard from being used in 2011 and later model year nonroad engines.

Providing short-term relief to those refiners that need additional time because they face hardship circumstances facilitates adoption of an overall program that reduces NRLM diesel fuel sulfur to 500 ppm beginning in 2007, and NRLM diesel fuel sulfur to 15 ppm in 2010 and 2012, for the majority of the industry. However, we do not intend for this waiver provision to encourage refiners to delay the planning and investments they would otherwise make. We do not expect to grant temporary waivers that apply to more than approximately one percent of the national NRLM diesel fuel pool in any given year.

The regulatory language for today's action includes a list of the information that must be included in a refiner's application for an extreme hardship waiver. If a refiner fails to provide all of the information specified in the regulations as part of its hardship application, we will deem the application void. In addition, we may request additional information as needed. Our experience to date shows that detailed technical and financial information from the companies seeking relief has been necessary to fully evaluate whether a hardship situation exists. The following are some examples of the types of information that must be contained in an application:

—The crude oil refining capacity and fuel sulfur level(s) of each diesel fuel product produced at each of the refiner's refineries.
—A technical plan for capital equipment and operating changes to achieve the NRLM diesel fuel sulfur standards.
—The anticipated timing for the overall project the refiner is proposing and key milestones to ultimately produce 100 percent of NRLM diesel fuel at the 15 ppm sulfur cap.
—The refiner's capital requirements for each step of its proposed projects.
—Detailed plans for financing the project and financial statements demonstrating the nature of and degree of financial hardship and how the requested relief would mitigate this hardship. This would include a description of the overall financial situation of the company and its plans to secure financing for the desulfurization project (*e.g.*, internal cash flow, bank loans, issuing of bonds, sale of assets, or sale of stock).
—A plan demonstrating how the refiner would achieve the standards as quickly as possible, including a timetable for obtaining the necessary capital, contracting for engineering and construction resources, obtaining any necessary permits, and beginning and completing construction.
—A description of the market area for the refiner's diesel fuel products.
—In some cases, it could also include a compliance plan for how the refiner's diesel fuel will be segregated through to the end-user and information on each of the end-users to whom its fuel is delivered.

We will consider several factors in our evaluation of any hardship waiver applications that we receive. Such factors include whether a refinery's configuration is unique or atypical; the proportion of non-highway diesel fuel production relative to other refinery products; whether the refiner, its parent company, and its subsidiaries are faced with severe economic limitations and steps the refiner has taken to attempt to comply with the standards, including efforts to obtain credits towards compliance. In addition, we will consider the total crude oil capacity of the refinery and its parent or subsidiary corporations, if any, in assessing the degree of hardship and the refiner's role in the diesel market. Finally, we will consider where the diesel fuel is intended to be sold in evaluating the environmental impacts of granting a waiver. Typically, because of EPA's comprehensive evaluation of both financial and technical information, action on hardship applications can take six or more months.

This extreme hardship provision is intended to address unusual circumstances that should be apparent now or could emerge in the near future. Thus, refiners seeking additional time under this provision must apply for relief by June 1, 2005, although we retain the discretion to consider hardship applications later as well for good cause.

3. Provisions for Transmix Facilities

In the petroleum products distribution system, certain types of interface mixtures in product pipelines cannot be added in any significant quantity to either of the adjoining products that produced the interface. These mixtures are known as "transmix." The pipeline and terminal industry's practice is to transport transmix via truck, pipeline, or barge to a facility with an on-site fractionator that is designed to separate the products. The owner or operator of such a facility is called a "transmix processor." Such entities are generally considered to be a refiner under existing EPA fuel regulations.

Transmix processors, like conventional refiners, are also currently subject to the "80 percent/20 percent" production requirement for 15 ppm and 500 ppm sulfur highway diesel fuel. This requirement, however, is inconsistent with the inherent nature of the transmix processors' business. Unlike conventional refiners, transmix processors refine batches of fuel that vary in volume and timing—largely unpredictably. Complying with set percentages of different highway diesel fuel sulfur grades would be very difficult, probably resulting in either a need to purchase credits or to postpone processing of some shipments. Transmix processors commented that it would not be appropriate to have any additional restrictions, beyond those based on sulfur content, imposed on their ability to market the fuel that they produce. They stated that the implementation of other restrictions, such as those under the highway diesel program's 80/20 requirement, would force them to ship large volumes of blendstocks back to refineries by truck, resulting in tank lock-outs that could cascade upstream though the distribution system potentially interfering with pipeline operations.[103]

Furthermore, transmix processors do not have the ability to change the nature of their products, as their processing equipment consists only of a distillation column to separate the blendstocks. This simple refinery configuration further limits their ability to install and operate a distillate hydrotreater. The commenters added that the sulfur content of the slate of fuel products that they produce is completely dependant on feed material that they receive, and that it is not feasible for them to install desulfurization equipment. We agree that it is not feasible for transmix processors to alter the sulfur content of the fuels that they produce and that limiting the market for these fuels could potentially lead to disruptions in the fuel distribution system.

In light of this disproportionate burden on transmix processors, today's final rule removes the restriction on the volume of highway or NRLM diesel fuel they produce, if they produce diesel fuel according to typical operational practices involving the separation of transmix and not, for example, by blending of blendstocks or processing crude or heavy oils. Therefore, under today's final rule, transmix processors may choose to continue to produce all of their highway diesel fuel to the 500 ppm sulfur standard until 2010. They may further choose to continue to produce all of their NRLM diesel fuel as high sulfur diesel fuel until June 1, 2010, all of their NRLM diesel fuel to the 500 ppm sulfur standard until June 1, 2014, and all of their LM diesel fuel to a 500 ppm sulfur limit indefinitely.

Transmix processors will be required to properly designate their fuel with the proper PTDs. Because the volume of fuel involved will be small and the fuel processed will already have been off-specification, we believe that providing this flexibility for transmix processors will have essentially no environmental impact and will not affect the efficient functioning of the NRLM diesel fuel program or the existing highway diesel fuel program. Rather, this approach will allow fuel volume to remain in the highway, NRLM, or LM (as applicable based on time frame) markets that might otherwise be forced into the heating oil market.

C. Special Provisions for Alaska and the Territories

1. Alaska

The nationwide engine emission standards established today apply to all NR engines throughout Alaska. The nationwide NRLM diesel fuel sulfur standards and implementation dates apply to NRLM diesel fuel used in the areas of Alaska served by the federal aid highway system (FAHS). In this final rule, EPA is not finalizing fuel sulfur standards and implementation deadlines for NRLM diesel fuel used in the areas of Alaska not served by the FAHS (*i.e.*, the "rural" areas). They will be addressed in a separate rulemaking to allow EPA to address the requirements for highway and NRLM diesel fuel in the rural areas in the same rulemaking. This final rule does, however, adopt the prohibition in the rural areas on the use of high sulfur (greater than 15 ppm) diesel fuel in model year 2011 and later nonroad engines, which will be manufactured to operate on ultra-low sulfur diesel fuel.

a. How Do the Highway Diesel Engine Standards, the Highway Diesel Fuel Standards, and Implementation Deadlines Apply in Alaska?

Unlike the rest of the nation, Alaska is currently exempt from the 500 ppm sulfur standard for highway diesel fuel and the dye provisions for diesel fuel not subject to this standard. Since the beginning of the 500 ppm sulfur highway diesel fuel program, we have granted Alaska exemptions from both the sulfur standard and dye provisions because of its unique geographical, meteorological, air quality, and economic factors.[104] On December 12, 1995, Alaska submitted a petition for a permanent exemption for all areas of the state served by the FAHS, that is, those areas previously covered only by a temporary exemption. While considering that petition, we started work on a nationwide rule to consider more stringent highway diesel fuel requirements for sulfur content.

In the January 18, 2001, highway diesel rule EPA fully applied the 2007 motor vehicle engine emission standards in Alaska. Based on factors unique to Alaska, we provided the state with: (1) An extension of the exemption from the 500 ppm sulfur fuel standard until the effective date of the new 15 ppm sulfur standard for highway diesel fuel in 2006; (2) an opportunity to request an alternative implementation plan for the 15 ppm sulfur diesel fuel program; and (3) a permanent exemption from the diesel fuel dye provisions. In response to these provisions in our January 18, 2001, highway rule, Alaska informed us that areas served by the FAHS, *i.e.*, communities on the connected road system or served by the Alaska state ferry system ("urban" areas), would follow the nationwide requirements.[105] Diesel fuel produced for use in areas of Alaska served by the FAHS will therefore be required to meet the same requirements for highway diesel fuel as diesel fuel produced for the rest of the nation. For the rural parts of the state—areas not served by the FAHS—Alaska requested that highway diesel fuel not be subject to the highway diesel fuel sulfur standard until June 1, 2010. Between 2006 and 2010, the rural communities would choose their own fuel management strategy, except that all 2007 model year and newer diesel vehicles would require ultra-low sulfur diesel fuel. Beginning June 1, 2010, all highway diesel fuel in the rural areas would be subject to the 15 ppm sulfur highway diesel fuel sulfur standard.[106]

[103] In a tank lock out situation a storage tank can no longer accept product from upstream in the distribution system because there is not sufficient outlet for the product it holds. A tank lock our downstream can quickly propagate upstream.

[104] Copies of information regarding Alaska?s petition for exemption, subsequent requests by Alaska, public comments received, and actions by EPA are available in public docket A–96–26.

[105] Letter and attached document to Jeffrey Holmstead of EPA from Michele Brown of the Alaska Department of Environmental Conservation, dated April 1, 2002. The communities on the connected road system or served by the Alaska State ferry system are listed in the attached document.

[106] Letter and attached document to Jeffrey Holmstead of EPA from Ernesta Ballard of the

Continued

EPA intends to propose and request comment on an amendment to the highway diesel sulfur rule to incorporate the rural area transition plan submitted by the state.

b. What NRLM Diesel Fuel Standards Are We Establishing for Urban Areas of Alaska?

Since Alaska is currently exempt from the 500 ppm sulfur standard for highway diesel fuel, we also considered exempting Alaska from the 500 ppm sulfur step of the proposed NRLM standards. However, despite the exemption, officials from the state of Alaska have informed us that some 500 ppm sulfur diesel fuel is nevertheless being marketed in many parts of Alaska. Market forces have brought the prices for 500 ppm diesel fuel down such that it is now becoming competitive with higher sulfur, uncontrolled diesel fuel. Assuming this trend continues, requiring that NRLM diesel fuel be produced to 500 ppm beginning June 1, 2007 would not appear to be unduly burdensome. Even if 500 ppm diesel fuel were not available in Alaska today, our expectation is that compliance with the highway program described above will likely result in the transition of all of the urban area highway diesel fuel distribution system to 15 ppm sulfur beginning in 2006. It could prove very challenging for the distribution system in some of the areas to segregate a 500 ppm sulfur grade of NRLM from a 15 ppm sulfur grade of highway and an uncontrolled grade for other purposes. We believe economics would determine whether the distribution system would handle the new grade of fuel or substitute 15 ppm sulfur highway diesel fuel for NRLM applications. Thus, in the 2007 to 2010 time frame, the NRLM market in some urban areas might be supplied with 500 ppm sulfur diesel, and in other areas might be supplied with 15 ppm sulfur diesel. For this reason, today's action applies the 500 ppm sulfur standard for NRLM diesel fuel to Alaska's urban areas.

Regardless of what occurs prior to 2010, we anticipate that 15 ppm sulfur highway diesel fuel will be made available in urban areas of Alaska by this time frame. The 2007 and later model year highway fleet will be growing, demanding more and more supply of 15 ppm sulfur diesel fuel. Adding nonroad volume to this would not appear to create any undue burden. Thus, today's action also applies the 15 ppm sulfur standard for NR and LM diesel fuel in the urban areas of Alaska, along with the rest of the nation beginning June 1, 2010 and June 1, 2012, respectively.

The state, in its comments on the proposal, supports today's action for the urban areas described above. One refiner in Alaska commented that we should implement a one-step approach requiring 15 ppm sulfur diesel fuel starting in 2010. The refiner indicated that, due to the limited NRLM market, the benefits of introducing 500 ppm sulfur diesel fuel in 2007 would be minimal. Also, the distribution system in Alaska is not capable of handling the two grades of diesel fuel that would be required between 2007 and 2010, thus 15 ppm sulfur fuel would be distributed as NRLM. We agree that the distribution system in Alaska is limited compared to the rest of the nation, and that consumption of diesel fuel by NRLM applications in Alaska is small. However, as previously discussed, we expect that some 500 ppm sulfur diesel fuel will be available due to market forces, and that 15 ppm sulfur highway diesel fuel will be available beginning in 2006 in the urban areas. Thus, requiring 500 ppm sulfur diesel fuel (or 15 ppm sulfur diesel fuel as a substitute) for the limited NRLM applications beginning in 2007 does not appear to create any undue burden on the fuel supply or the distribution system in urban Alaska.

During the development of the original 500 ppm sulfur highway diesel fuel standards in the early 1990's, refiners and distributors in Alaska expressed concern that if Alaska were required to dye its non-highway diesel fuel red along with the rest of the country, residual dye in tanks or other equipment would be enough to contaminate and disqualify Jet-A kerosene used as aviation fuel. Since much of the diesel fuel in Alaska is No. 1 and is indistinguishable from Jet-A kerosene, not only would tanks and transfer equipment have to be cleaned, but separate tankage would be needed. Consequently, we granted Alaska temporary exemptions from the dye requirement and in the January 18, 2001, highway diesel rule granted the state a permanent exemption.

The proposed use of a marker for heating oil in the 2007–10 time period presents similar concerns in Alaska's distribution system. In response to our request for comments on this issue, the state and refiners indicated that Alaska's system is not capable of accommodating dyes or markers and segregation. The priority of the state and fuel industry is to keep dyes and markers out of the fuel stream to prevent contamination of Jet-A and facilitate movement of the fuel. The comments suggested that implementation of refiner product designations, labeling of fuel pumps, retailer education, and rapid transition to ULSD would ensure that 500 ppm sulfur diesel fuel is used in NRLM equipment from 2007–10 and that 15 ppm sulfur diesel fuel is used in nonroad equipment after 2010.

In section IV.D below, we discuss the provisions that we are adopting for the State of Alaska that will allow us to enforce the NRLM diesel fuel program without requiring the fuel marker.

c. Why Are We Deferring Final Action on NRLM Diesel Fuel Standards for Rural Areas of Alaska?

We are deferring final action on the fuel sulfur standards and implementation deadlines for the rural areas of Alaska. We proposed to permanently exempt NRLM diesel fuel used in the rural areas from fuel content standards, except that diesel fuel used in 2011 and later model year nonroad engines would have had to meet the sulfur content standard of 15 ppm sulfur. However, this proposed action is inconsistent with the action requested by the state in its comments to the proposal. It is also inconsistent with the state's alternative implementation plan for highway diesel fuel in rural Alaska, which was submitted after publication of the proposal.

We intend to issue a supplemental proposal that would address both highway and NRLM diesel fuel sulfur standards for Alaska's rural areas. This proposal will address the comments submitted by the state, as well as the state's alternative implementation plan for highway diesel fuel.

2. American Samoa, Guam, the Commonwealth of Northern Mariana Islands, and Puerto Rico

a. What Provisions Apply in American Samoa, Guam, and the Commonwealth of Northern Mariana Islands?

As we proposed, we are excluding American Samoa, Guam and the Commonwealth of the Northern Mariana Islands (CNMI) from the NRLM diesel fuel sulfur standards and associated requirements. We also are excluding these territories from the tier 4 nonroad engine emissions standards, and other requirements associated with those emission standards. The territories will continue to have access to new nonroad diesel engines and equipment using pre-tier 4 technologies, at least as long as manufacturers choose to market those technologies. In the future, if manufacturers choose to market nonroad diesel engines and equipment only with tier 4 emission control

Alaska Department of Environmental Conservation, dated June 12, 2003.

technologies, we believe the market will determine if and when the territories will make the investment needed to obtain and distribute the diesel fuel necessary to support these technologies.

We are also requiring that all nonroad diesel engines and equipment for these territories be certified and labeled to the applicable requirements—either to the previous-tier standards and associated requirements under this exclusion, or to the Tier 4 standards and associated requirements applicable for the model year of production under the nationwide requirements of today's action. The engines would still be emissions warranted, as otherwise required under the CAA and EPA regulations. Special recall and warranty considerations due to the use of excluded high sulfur fuel would be the same as those for Alaska during its exemption and transition periods for highway diesel fuel and for these territories for highway diesel fuel (see 66 FR 5086, 5088, January 18, 2001).

To protect against circumvention of the emission requirements applicable to the rest of the U.S., we are restricting the importation of nonroad engines and equipment from these territories into the rest of the U.S. After the 2010 model year, nonroad diesel engines and equipment certified under this exclusion for sale in American Samoa, Guam and the Commonwealth of the Northern Mariana Islands will not be permitted entry into the rest of the U.S.

b. Why Are We Treating These Territories Uniquely?

Like Alaska, these territories are currently exempt from the 500 ppm sulfur standard for highway diesel fuel. Unlike Alaska, they are also exempt from the new highway diesel fuel sulfur standard effective in 2006 and the new highway vehicle and engine emission standards effective beginning in 2007 (see 66 FR 5088, January 18, 2001).

Section 325 of the CAA provides that upon request of Guam, American Samoa, the Virgin Islands, or the Commonwealth of the Northern Mariana Islands, we may exempt any person or source, or class of persons or sources, in that territory from any requirement of the CAA, with some specific exceptions. The requested exemption could be granted if we determine that compliance with such requirement is not feasible or is unreasonable due to unique geographical, meteorological, or economic factors of the territory, or other local factors as we consider significant. Prior to the effective date of the current highway diesel fuel sulfur standard of 500 ppm, the territories of American Samoa, Guam and the Commonwealth of the Northern Mariana Islands petitioned us for an exemption under section 325 of the CAA from the sulfur requirement under section 211(i) of the CAA and associated regulations at 40 CFR 80.29. We subsequently granted the petitions.[107] Consistent with this decision, in our January 18, 2001 highway rule (66 FR 5088), we determined that the 2007 heavy-duty engine emission standards and 2006 diesel fuel sulfur standard would not apply to these territories.

Compliance with the NRLM diesel fuel sulfur standards would result in major economic burden on the territories. All three of these territories lack internal petroleum supplies and refining capabilities and rely on long distance imports. Given their remote location from Hawaii and the U.S. mainland, most petroleum products are imported from east rim nations, particularly Singapore. Australia, the Philippines, and certain other Asian countries are beginning to consider and in some cases implement lower sulfur diesel fuel standards. However, it is not clear that supply, especially of 15 ppm sulfur diesel fuel, would be possible to these territories.

Furthermore, compliance with new 15 ppm sulfur requirement for highway diesel fuel beginning in 2006 and today's 15 ppm sulfur requirement for NRLM diesel fuel beginning in 2010 (or the 500 ppm sulfur requirement for NRLM diesel fuel beginning 2007) would require construction of separate storage and handling facilities for a unique grade of diesel fuel for highway and nonroad purposes, or use of 15 ppm sulfur diesel fuel for all diesel applications to avoid segregation. Either of these alternatives would require importation of 500 and 15 ppm sulfur diesel fuel from Hawaii or the U.S. mainland, and would significantly add to the already high cost of diesel fuel in these territories, which rely heavily on U.S. support for their economies. At the same time, it is not clear that the environmental benefits in these areas would warrant this cost. Therefore, we are not applying the fuel and engine standards to these territories.

The Caribbean Petroleum Corporation (CPC) commented that the proposed nonroad diesel rule would result in a major economic burden for Puerto Rico, the environmental benefits do not warrant the cost, and that Puerto Rico should be exempt. However, the CPC did not include any cost or environmental information to support its claims. We have no reason to believe that the costs of the NRLM diesel fuel program in Puerto Rico will be significantly greater than that of the U.S. For example, Puerto Rico is close to the U.S. mainland, and to South American and Central American suppliers of fuel to the U.S. mainland, and therefore has ready access to nearby fuel supplies that meet U.S. requirements. Similar to the fuel distribution system in the rest of the country, the fuel distribution system in Puerto Rico is geared to separate fuel handling and storage facilities for highway and non-highway diesel fuels. Today's rule will require additional segregation for the NRLM diesel fuels, but no differently for Puerto Rico than for the U.S. Nevertheless, to avoid that additional fuel segregation, Puerto Rico could substitute highway fuel for use in NRLM diesel engines and equipment. We also believe that the important air quality benefits to be realized by today's rule for the four million people in Puerto Rico should not be significantly different than those for the rest of the country. Consequently, today's rule includes Puerto Rico in the NRLM diesel fuel program.

D. NRLM Diesel Fuel Program Design

In addition to specifying the sulfur standards and the implementation dates when the standards take effect, the diesel fuel program compliance provisions must be designed and structured carefully to achieve the overall principles of the program. Specifically, the health and welfare benefits of the NRLM diesel fuel and the highway diesel programs, and the need for widespread availability of 15 ppm sulfur highway diesel fuel must be maintained. The program benefits and fuel availability will only happen if the NRLM diesel fuel program is designed such that the amount of 15 ppm sulfur fuel expected to be produced under the highway diesel fuel program is in fact produced and that 500 ppm highway fuel is not overproduced. Likewise, the benefits of the NRLM diesel fuel sulfur standards adopted today will only be achieved if the program is designed to ensure that the volume of diesel fuel consumed by NRLM diesel engines is matched by the supply of NRLM diesel fuel produced to the appropriate low sulfur levels. At the same time, promoting the efficiency of the distribution system calls for fungible distribution of physically similar products, and minimizing the need for product segregation.

As discussed below, the situation faced in 1993 when EPA first regulated the sulfur content of highway diesel fuel parallels some of the issues that EPA

[107] *See* 57 FR 32010, July 20, 1992 for American Samoa; 57 FR 32010, July 30, 1992 for Guam; and 59 FR 26129, May 19, 1994 for CNMI.

needed to address in today's rule. Prior to the implementation of the 500 ppm sulfur standard for highway diesel fuel in 1993, most No. 2 distillate fuel was produced to essentially the same specifications, shipped fungibly, and used interchangeably by highway diesel engines, nonroad diesel engines, locomotive and marine diesel engines, and heating oil applications. Beginning in 1993, highway diesel fuel was required to meet a 500 ppm sulfur cap and was segregated from other distillate fuels as it left the refinery by the use of a visible level of dye solvent red 164 in all non-highway distillate. At about the same time, the Internal Revenue Service (IRS) similarly required non-highway diesel fuel to be dyed red to a much higher concentration prior to retail sale to distinguish it from highway diesel fuel for excise tax purposes. Dyed non-highway fuel is exempt from this tax. This splitting of the distillate pool necessitated changes in the distribution system to ship and store the now distinct products separately. In some parts of the country where the costs to segregate non-highway diesel fuel from highway diesel fuel could not be justified, both fuels have been produced to highway specifications.[108]

1. Requirements During the First Step of the Fuel Program

EPA is adopting specific compliance provisions during the first step of today's NRLM diesel fuel sulfur control program for three reasons. The first is to maintain the integrity of the highway diesel program, while allowing the efficient distribution of highway and NRLM diesel fuel. Since 500 ppm sulfur highway diesel fuel allowed under the highway diesel fuel program's Temporary Compliance Option (TCO) and NRLM diesel fuel meeting today's 500 ppm sulfur standard will be physically the same, it would be impossible to maintain the benefits and program integrity of the highway diesel fuel program without some means of differentiating highway diesel fuel from NRLM diesel fuel.

Continuing the current practice of dyeing NRLM diesel fuel at the refinery gate and requiring that it be segregated throughout the distribution system is not a practical way to differentiate NRLM diesel fuel from highway fuel. At the same time, allowing the unrestricted fungible distribution of highway and NRLM diesel fuel with the same sulfur level risks the loss of important benefits of the highway program. For example, if a refiner produced all 500 ppm sulfur fuel and designated it as NRLM diesel fuel, that refiner would have no obligation to produce any 15 ppm sulfur highway diesel fuel. Without an effective way of limiting the use in the highway market of 500 ppm sulfur diesel fuel produced as NRLM diesel fuel, much more 500 ppm sulfur fuel could, and likely would find its way into the highway market than would otherwise happen under the current highway program. This would displace 15 ppm sulfur diesel fuel that would have otherwise been produced. This likely series of events would circumvent the intent of the highway program's TCO and sacrifice some of the resulting PM and SO_2 emission benefits of the overall highway diesel program. If this occurred to any significant degree, it could also undermine the integrity of the highway program by threatening the availability of 15 ppm sulfur diesel fuel nationwide for the vehicles that need it. This is no longer a concern after 2010, when all highway diesel fuel is required to meet a 15 ppm sulfur standard.

The second reason is to maintain the integrity of the NRLM diesel fuel program, while allowing the efficient distribution of NRLM diesel fuel and heating oil where they have similar sulfur levels. By establishing new sulfur standards for NRLM diesel fuel but not heating oil, today's program creates the need to distinguish the fuel used for these two purposes. Currently, there is no grade of diesel fuel which is produced and marketed as a distinguishable grade for NRLM diesel engine uses. It is typically produced and shipped fungibly with other distillate used for heating oil purposes, and it is all dyed red in accordance with EPA and IRS regulations. Because today's rule includes small refiner and credit provisions that allow the limited production of high sulfur (greater than 500 ppm) NRLM diesel fuel through 2010, it is not possible to rely on sulfur content alone to differentiate NRLM diesel fuel from heating oil during the first step of the program. Without adequate controls, a refiner could choose not to desulfurize any of its fuel that is destined for the NRLM diesel fuel market, instead designating that volume as heating oil at the refinery gate. This fuel, ostensibly manufactured for use as heating oil could be misdirected for use in NRLM diesel equipment, and would be indistinguishable from legal high sulfur NRLM diesel fuel produced by small refiners and/or through the use of credits. This could substantially reduce the environmental benefits of today's rule.

After 2010, when the 15 ppm sulfur standard for NR diesel fuel goes into effect, small refiner and credit NR fuel must meet a 500 ppm standard. Therefore, after 2010 NRLM diesel fuel can be distinguished from high sulfur (greater than 500 ppm) home heating fuel based on sulfur content. However, 500 ppm NR (small refiner, credit) produced from June 1, 2010 through May 31, 2012, and 500 ppm NRLM (small refiner, credit) diesel fuel produced from June 1, 2012 through May 31, 2014, could not be distinguished from heating oil produced to meet a similar 500 ppm sulfur limit. Likewise, from June 1, 2010 to June 1, 2012, 500 ppm NR (small refiner, credit) diesel fuel and LM diesel fuel need to be distinguished from each other, so that diesel fuel produced as 500 ppm LM is not later misdirected to the NR diesel market. Such misdirected 500 ppm sulfur LM diesel fuel would be indistinguishable from legal 500 ppm sulfur NR diesel fuel, reducing the environmental benefits of today's rule. These various 500 ppm fuels could not be distinguished based on sulfur level. As previously discussed, the situation which was faced in 1993 regarding the need to differentiate 500 ppm sulfur highway diesel fuel from other diesel fuel is similar to the need today to differentiate highway diesel fuel, NRLM diesel fuel, and heating oil.

The third reason is to maintain the integrity of the anti-downgrading requirements in the highway diesel program. The highway diesel program requires that each entity in the distribution system downgrade no more than 20 percent of the 15 ppm sulfur highway diesel fuel for which it assumes custody to 500 ppm sulfur highway diesel fuel. These provisions are necessary to ensure the widespread availability of 15 ppm sulfur diesel fuel for use in model year 2007 and later highway vehicles, in which the use of 15 ppm sulfur fuel is essential to facilitate the projected emissions benefits of the highway program. The highway program placed no restrictions on the volume of highway diesel fuel that could be downgraded to NRLM diesel fuel. Under the proposed rule there would be no way to distinguish 500 ppm sulfur NRLM diesel fuel from 500 ppm sulfur highway diesel fuel downstream of the refinery. Therefore, to preserve the integrity of the highway program, the proposal would have made the highway program's anti-downgrade requirements more stringent by also

[108] Diesel fuel produced to highway specifications but used for non-highway purposes is referred to as "spill-over." It leaves the refinery gate and is fungibly distributed as if it were highway diesel fuel, and is typically dyed at a point later in the distribution system. Once it is dyed it is no longer available for use in highway vehicles, and is not part of the supply of highway fuel.

restricting downgrades to 500 ppm sulfur NRLM diesel fuel. We received several negative comments on this proposed restriction. The compliance and record keeping requirements finalized to address the two concerns discussed above, can be utilized to facilitate the implementation of the highway program's anti-downgrading requirements without the need to further restrict downgrading. As a result, today's rule also contains several modifications which clarify the anti-downgrading provisions of the highway diesel program.

The requirements described below will help ensure that the projected benefits of the highway diesel program and of today's NRLM diesel program are achieved.

a. Ensuring Refiner Production Volumes of 15 ppm Sulfur Highway Diesel Fuel Are Consistent With the Highway Rule's 80/20 Requirement

To avoid adding unnecessary cost to the fuel distribution system, we proposed that the current requirement of dyeing non-highway distillate fuels at the refinery gate become voluntary as of June 1, 2006.[109] As discussed in the proposal, continuing to require that NRLM diesel fuel and heating oil contain a visible trace of red dye at the refinery gate would allow for simple enforcement of the highway standards throughout the duration of the highway program's TCO. Clear, undyed diesel fuel would have to meet the 80/20 ratio of 15 ppm to 500 ppm sulfur highway diesel fuel, and dyed fuel could only be used in NRLM diesel equipment or as heating oil. Continuing the current dye provisions would therefore ensure that the intended benefits of the highway program are achieved. However, maintaining this dye distinction would also require segregation of a new grade of dyed 500 ppm sulfur NRLM diesel fuel throughout the entire distribution system. The costs of requiring segregation of two otherwise identical fuels throughout the entire distribution system could be quite substantial.[110] Comments on the proposed rule confirmed EPA's assessment that the ability of the fuel distribution system to distribute these fuels fungibly is essential, since segregating the fuels could result in substantial additional transportation costs and necessitate additional storage tanks throughout the system.

The NPRM invited comment on two alternative approaches to ensure that refiner production of 15 ppm sulfur highway diesel fuel met the highway rule's 80/20 requirement; the "refiner baseline" approach, and the "designate and track" approach. The baseline approach is essentially a constraint on the sulfur levels of the various distillate fuel products a refiner produces, based on historical production volumes. Fuel with similar sulfur levels could then be fungibly distributed with only limited controls on the downstream distribution system. The designate and track approach requires that a refiner designate into which market discrete volumes of the distillate fuels it produces must be sold, without any consideration of historical production volumes. The fuel must then be tracked through the distribution system and sold only for its designated purpose (or a purpose that requires less control). As with the baseline approach, diesel fuel with similar sulfur levels could be fungibly shipped up to the point of distribution from a terminal where off-highway diesel fuel must be dyed red pursuant to IRS requirements to indicate its tax exempt status.

We proposed the baseline approach because, in the absence of a red dye requirement at the refinery-gate for NRLM diesel fuel, we expected that it would: (1) Allow for the fungible distribution of 500 ppm sulfur highway and NRLM diesel fuel; (2) ensure the enforceability of the highway diesel fuel and NRLM diesel fuel standards; (3) maintain the projected production volume of 15 ppm sulfur highway diesel fuel; (4) allow refinery production of 500 ppm sulfur NRLM diesel fuel and heating oil to remain flexible to meet market demand; and (5) enable the efficient distribution of diesel fuel while imposing the least burden on the parties in the fuel production and distribution system. In the proposal, we also discussed how a refiner's baseline would be set, and invited comment on ways to account for changes refiners might make from their historical production practices in response to the highway diesel program.

In the NPRM, we expressed concerns that a designate and track approach would raise significant workability and enforceability issues and therefore might not maintain the integrity of highway and NRLM diesel fuel sulfur programs. Our concerns about the workability and enforceability of a designate and track approach amplified potential concerns regarding whether the approach might reduce the volume of 15 ppm sulfur diesel fuel required to be produced under the highway diesel program, leading to a reduction in the environmental benefits of the highway diesel program and calling into question the availability of 15 ppm sulfur diesel fuel. We were also concerned about whether this approach would place too much burden on the numerous entities in the fuel distribution system, as compliance was focused on downstream parties. While the designate and track approach provided greater production flexibility to refiners than the baseline approach, it appeared to increase the burden and restrictions on downstream parties.

Of the approaches discussed in the NPRM, we expected that the baseline approach would provide the best mechanism to achieve the fuel program goals described at the beginning of this section. Since the proposal, we have comprehensively evaluated the advantages and disadvantages of both approaches. Based on this review, we now believe that a baseline approach would produce significant adverse problems because of its overly restrictive impact on the ability of fuel producers and distributors to efficiently respond to the myriad and daily needs of the markets for highway and NRLM diesel fuel. Implementation of the approach could also produce an unintended bias that would tend to reduce the benefits of the highway program and reduce the availability of 15 ppm sulfur highway diesel fuel. At the same time, our review of the approaches shows that the designate and track approach can be implemented in an enforceable manner and likely would not cause a reduction in the environmental benefits of the highway diesel program or adversely impact the widespread availability of 15 ppm sulfur highway diesel fuel. Our evaluation of these alternate approaches is discussed in more detail in the following sections.

i. Proposed Refiner Baseline Approach

Under the refiner baseline approach, we proposed that from June 1, 2007 through May 31, 2010, any refiner or importer could choose to distribute its 500 ppm sulfur NRLM and highway diesel fuels fungibly without adding red dye at the refinery gate. Refiners and importers who elect to distribute these fuels fungibly would need to establish a non-highway distillate baseline, defined as a percentage of its total distillate fuel production volume based on historical production data. For future production

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[109] The IRS requirements concerning dyeing of non-highway fuel prior to sale to consumers are not changed by this rulemaking.

[110] Under the highway program the potential exists to add a third grade of diesel fuel in an estimated 40 percent of the country, and we projected one-time tankage and distribution system costs of $1.05 billion to accomplish this. Using similar assumptions, to add a second 500 ppm grade nationwide would cost in excess of $2 billion. This assumes that the capability exists to add such new tankage.

purposes, this percentage of the volume of diesel fuel produced would have to either meet the 500 ppm sulfur NRLM diesel fuel sulfur standard or be marked as heating oil. All the remaining production of diesel fuel would have to meet the requirements of the highway fuel program (*i.e.*, 80 percent of this fuel would have to meet a 15 ppm sulfur cap). Refiners not wishing to participate in the baseline approach would have to dye all of their 500 ppm sulfur NRLM diesel fuel at the refinery. However, we anticipated that few refiners would opt to dye 500 ppm sulfur NRLM diesel fuel, other than the volumes that they dispense from their own racks, since this would eliminate the ability to fungibly distribute 500 ppm sulfur highway and NRLM diesel fuels.

Since the publication of the proposed rule, we have developed a better understanding of refiner concerns about the constraints associated with the baseline approach. Specifically, it is now clear that individual refiners would be significantly constrained by the baseline approach from efficiently responding to changes in contract arrangements with their clients and changes in market demands. Refiners commented that they win and lose contracts on a daily basis and that depending on which contracts they secure, they may not be able to comply with their baseline. Specific concerns were raised regarding the ability of refiners to compensate for the loss of export contracts and to respond to spikes in the demand for heating oil which periodically result from an unexpectedly cold winter. Refiners also related that the constraints under the baseline approach could cause an anti-competitive dynamic between fuel refiners and their customers.

Based on our reevaluation of the baseline approach and the information gathered from the public comments, it is now clear that the constraints on the slate of fuels that a refiner produces under the baseline approach could interfere with a refiner's ability to meet market demands, which in turn could result in supply shortages and increased fuel prices. For example, if a refiner were to lose an export contract for high sulfur diesel fuel, the baseline approach could prevent that refiner from seeking to market that product domestically. This could impact the overall supply of diesel fuel since the refiner may not have sufficient facilities to desulfurize diesel fuel. Also, knowing that losing such an export contract would leave the refiner with no ability to market its fuel domestically could give the refiner's export client an undue advantage during contract negotiations.

In the case of a spike in heating oil demand due to an unusually cold winter, the baseline approach would limit a refiner's ability to produce additional volumes of high sulfur distillate fuel beyond the volume established under its baseline. Refiners that were limited in their ability to produce additional high sulfur fuel could choose to supply low sulfur diesel fuel to the heating oil market. However, they may not have sufficient hydrotreating capacity to do so. This could limit their ability to respond to a supply shortage.

The proposed rule suggested various potential modifications to the baseline approach to address refiner concerns regarding the associated constraints on the slate of fuels they produce. We received comments on the potential modifications discussed in the NPRM as well as other potential changes to the baseline approach. Some commenters suggested that if EPA were to finalize a baseline approach, refiners should be able to apply to EPA for a yearly adjustment to their baseline based on annual demand forecasts. Even with such flexibility, refiners still concluded that in many cases they would likely be forced to dye their fuel instead. For fuel distributors, having refiners dye their NRLM diesel fuel presented an unacceptable situation due to the need to distribute another grade of fuel. As a result, all comments from the refining and fuel distribution community were in agreement that the baseline approach may be unworkable.

Based on our review of the comments and our discussions with fuel producers and distributors, it has become clear that none of the potential modifications to the baseline approach would adequately compensate for the inherent inflexibility of requiring refiners to comply with set production ratios. Even if EPA were to adjust such ratios on an annual basis, refiners might need to approach EPA for an interim adjustment if their contractual agreements changed or if market demand shifted unexpectedly. The process of evaluating requests for baseline adjustments could be very burdensome to the industry and to EPA, and EPA would unlikely be able to respond quickly enough to changing market conditions.

More importantly, all of the potential alternatives that we might implement to mitigate the constraints of the baseline approach could potentially undermine the environmental benefits of the highway program. Such alternatives all would involve granting allowances to some refiners to produce additional volumes of non-highway fuels above the set baseline to facilitate a refiner meeting the market demand for such fuels. At the same time, it would not be possible for EPA to reduce the ability of other refiners to produce non-highway fuel who may have lost these markets. Therefore, for such alternatives to be effective in responding to changing market conditions, an unintended downward bias would result regarding the required production of 15 ppm sulfur highway diesel fuel.

Even without any changes we discovered from the highway diesel program pre-compliance reports that the proposed baseline approach has a downward bias that could result in a reduction in the volume of 15 ppm sulfur diesel fuel produced under the highway diesel program.[111] We proposed that refiners could choose to calculate their off-highway baseline using either an average of 2003 through 2005 production data or 2006 production data. Providing the option for a 2006 baseline was necessary because a number of refiners will be changing the slate of fuels that they produce in response to the highway diesel rule which becomes effective in 2006. While the highway diesel pre-compliance reports indicate an overall increase in production volume, they also indicate that 40 percent of highway diesel refiners will decrease the volume of highway diesel fuel they produce. If all of these refiners were to take a 2006 baseline to determine the volume of 15 ppm sulfur diesel fuel they would be required to produce, a substantial drop in the total volume of 15 ppm sulfur diesel fuel produced could result.

The pre-compliance reports indicate that the other 60 percent of refiners will be increasing the volume of highway diesel fuel they produce. We projected that these shifts in the slate of fuel products that refiners produce would have an overall positive impact on diesel fuel supply. However, refiners that increase the volume of highway fuel they produce would likely chose to calculate their baseline using their lower 2003–2005 production volumes. Doing so would result in a lower percentage of their distillate fuel that would be required to be produced for highway diesel use, and subject to a 15 ppm sulfur standard.

The volume of spillover could also be reduced refiners were to dye 500 ppm sulfur diesel they manufactured to meet anticipated NRLM diesel fuel demand in order to avoid needing to comply with the baseline approach. Many refiners commented that they

[111] "Summary and Analysis of the Highway Diesel Fuel 2003 Pre-compliance Reports," EPA 420–R–03–103, October 2003.

considered the baseline approach so unworkable and onerous that they would choose to dye all of their 500 ppm sulfur NRLM diesel fuel at the refinery gate. This could force some parts of the distribution systems which had previously not carried two grades of diesel fuel for highway and off-highway uses to begin doing so.

In summary, we are not finalizing the proposed baseline system because we believe—

1. It could unnecessarily constrain refiners ability to meet market demands, encouraging them to dye 500 ppm sulfur NRLM diesel fuel at the refinery resulting in an added burden to the distribution system;

2. It could create a bias that could result in a loss in the volume of 15 ppm sulfur highway diesel fuel produced, and the options to remove these market constraints would only increase the bias to reduce the volume of 15 ppm sulfur highway diesel fuel; and

3. The baseline approach would not ensure that the environmental benefits of the 2007 highway diesel program would be maintained.

ii. Designate and Track Approach

At the time of the NPRM, we invited comment on an alternative to the baseline approach called the "designate and track" approach. Under the envisioned designate and track approach, refiners and importers would designate the volumes of 500 ppm sulfur diesel fuel they produce/import as either highway or NRLM diesel fuel and would ship them fungibly. These designations would follow the fuel through the distribution system and be used to restrict the sale of 500 ppm sulfur NRLM diesel fuel from the highway market. While we sought comment on various forms of the designate and track approach, we also expressed serious reservations regarding its workability, enforceability, impact on the benefits of the highway rule, and constraints on the distribution system. For example, at the time of the proposal, refiners supported a designate and track approach where certain parts of the distribution system (*e.g.*, pipelines) did not have to report. EPA believed that such an approach was unenforceable. Refiners were also supporting the designate and track approach as an option for refiners to choose in addition to the baseline approach. However, EPA believed that the two approaches were incompatible.

As noted in the proposal, the designate and track approach allows maximum flexibility for refiners and importers, but EPA had concerns that the volume reconciliation requirements would inappropriately restrict the flexibility of downstream parties to respond to market changes. EPA also had concerns that it would reduce the amount of 15 ppm spillover from the highway market, reducing the environmental benefits of that rule.

Since the proposal, we received extensive input both in the written comments and through in-depth meetings with representatives of all segments of the fuel distribution industry on how the designate and track system might be structured to provide the needed compliance oversight without placing an undue burden on industry. Refiners now agree that the designate and track approach should not be an option for refiners in addition to the baseline approach, and support it as a stand alone approach. All parties in the fuel distribution system have also now expressed support for the record keeping and reporting requirements associated with tracking designated fuel volumes through each custodian in the distribution chain until the fuel leaves the terminal either taxed or dyed. Furthermore, commenters from all segments of the fuel distribution industry from the refiner through to the terminal stated that the information needed to support the designate and track approach is already kept as part of normal business practices. Commenters stated that only modest upgrades in their record keeping procedures would be needed to compile the needed information and that preparing the necessary reports would not represent a significant burden. Thus, our concerns that a designate and track approach might represent a large burden to fuel distributors were unfounded.

In addition, we have developed appropriate solutions to the various open questions and issues that we had with the designate and track approach at the time of the proposal. In the proposal it was unclear how a designate and track approach would be structured to account for the swell in highway diesel fuel volumes in the winter that results from downstream kerosene blending to improve cold flow properties. Without an adequate control mechanism, normal swell in downstream highway diesel fuel volumes in the North due to kerosene blending during winter months could mask the inappropriate shifting of NRLM-designated 500 ppm sulfur fuel to the highway diesel pool. We have developed an appropriate mechanism to address this situation as described in section IV.D.3.

In the proposal, we also expressed concerns regarding how normal volumetric fluctuations in the distribution system such as those caused by product downgrading in pipelines could be adequately accounted for under a designate and track system so that such fluctuations would not mask the inappropriate shifting of 500 ppm sulfur NRLM diesel fuel to the highway pool. We have subsequently developed a periodic volume account balance system to account for such fluctuations.

Through discussions with terminal operators, we have also resolved concerns expressed in the NPRM that a designate and track approach might limit a terminal operator's ability to respond to shifts in demand for 500 ppm sulfur highway versus NRLM diesel fuel. To avoid this potential problem today's rule allows terminal operators and others to switch the designation of 500 ppm sulfur NRLM diesel fuel to highway diesel fuel on a temporary basis but not on a cumulative basis over time. This will allow terminal operators to sell NRLM designated 500 ppm sulfur fuel into the highway market provided that they later sell the same volume of highway-designated 500 ppm sulfur fuel into the NRLM market. To ensure that 500 ppm sulfur NRLM diesel fuel is not inappropriately shifted into the highway diesel pool, terminal operators will need to demonstrate that the volume of 500 ppm sulfur highway diesel fuel they delivered is less than or equal to the volume received.

In the NPRM, we stated that determining the responsible party for a violation of the restriction against shifting 500 ppm sulfur NRLM diesel fuel into the highway pool would be difficult under a designate and track approach because a number of parties in the distribution chain take custody of the fuel without taking ownership. However, this concern can be addressed by structuring the provisions to hold the custodian of the fuel accountable for any such violation that takes place while the fuel is in their custody. Review of electronic data submitted from all custodians in the highway and NRLM diesel fuel distribution chain will reveal the custodian responsible for a violation. By comparing such data on the hand-offs of designated fuel volumes between all adjacent pairs of custodians in the distribution chain for discrepancies, we can identify any party responsible for inappropriately shifting volumes of 500 ppm sulfur fuel designated for use in NRLM equipment to the highway market. Many terminals do not take ownership of the fuel that they handle. Terminals that lease storage tanks to multiple owners will need to enter into contractual agreements with their tenants to ensure that they understand their obligations as a custodian of designated fuel and do not inappropriately change the designation of fuels stored in such leased tanks.

An effective enforcement and compliance assurance program must include the ability to rapidly and accurately review the large amount of data on the hand-offs of designated fuel volumes for discrepancies. This can be accomplished if all parties report electronically to a database which can reconcile hand-off volumes between all parties in the distribution chain in an automated fashion. All segments in the fuel distribution system are now in support of providing the necessary information to such an electronic reporting system. We have conducted a review of the Agency resources that would be needed to compile the industry reports on the transfer of designated fuel volumes, perform quality assurance on these data, and to perform the necessary analysis of the database to discover potential violations. Our review indicates that the reporting forms can be standardized and the review process automated in such a fashion as to minimize the Agency resource requirements, while at that same time ensuring the quality of the data and completeness of the review process. In light of the above discussion, we are now convinced that a designate and track approach can be designed to meet our enforcement and compliance assurance needs under today's rule.

In addition to concerns regarding the workability and enforceability of a designate and track approach, the NPRM expressed concerns that application of such an approach could reduce the benefits of the highway diesel program by reducing the amount of highway diesel fuel that is used in nonroad equipment due to the logistical constraints in the distribution system ("spillover"). Specifically, it was thought that the opportunity to fungibly ship batches of 500 ppm sulfur NRLM diesel fuel and 500 ppm sulfur highway diesel fuel might allow refiners to supply highway and NRLM diesel fuel to markets where they would otherwise have supplied just highway fuel for both purposes. Our reevaluation since the proposal indicates that this is not a significant concern. As noted earlier, there are currently substantial regions of the country where only highway diesel fuel is supplied by bulk shipments to both the highway and NRLM markets due to the high costs associated with segregating an additional distillate grade in the distribution system.[112] These are the same areas where the majority of spillover occurs today. After the highway diesel program becomes effective in 2006, we project that only 15 ppm sulfur highway diesel fuel will be supplied in bulk shipments to both the highway and NRLM markets in most of these same areas. Although 500 ppm sulfur highway diesel fuel could be shipped in bulk to these areas through 2010 under the highway program's TCO, the potential demand for such fuel and for 500 ppm sulfur NRLM diesel fuel would not be sufficient to justify the cost of segregating an additional grade of 500 ppm sulfur diesel fuel in these areas for a short period of time. The designate and track approach does not impact the costs of segregation, and therefore is not expected to change distribution patterns that are based on these costs.

After 2010, when 500 ppm sulfur highway fuel no longer exists, the total volume of 500 ppm sulfur diesel fuel in the distribution system will be substantially reduced, and there will be even less incentive to distribute an additional grade of 500 ppm sulfur diesel fuel in bulk. Therefore, the only areas where substantial flexibility will exist under today's program to supply either highway or NRLM diesel fuel to the NRLM market is in areas where this flexibility exists today. Despite this flexibility in the current regulations, spillover currently still occurs. Therefore, we project that there will be little additional potential due to today's rule for refiners to reduce highway spillover into the NRLM market under a designate and track approach and that such spillover levels would not be significantly reduced from historical levels. In contrast, as discussed above, we now believe that the baseline approach would have resulted in a significant loss of 15 ppm diesel production.

Furthermore, concerns regarding a potential reduction in the spillover of 15 ppm sulfur highway diesel into the NRLM markets has been lessened by the information provided in the highway program pre-compliance reports. These reports suggest that more than 95 percent of highway diesel fuel will be produced to a 15 ppm sulfur standard beginning in 2006. In calculating the projected benefits of the highway diesel program, we assumed that only 80 percent of highway diesel fuel would meet a 15 ppm sulfur standard. Therefore, the actual benefits of the highway program will be substantially greater than estimated if the projections in the pre-compliance reports are realized.

Based on the above discussion, we believe that the concerns regarding the designate and track approach's workability, enforceability, and ability to preserve the benefits of the highway program and today's NRLM diesel fuel program have been satisfactorily resolved.

b. Ensuring That Heating Oil Is Not Used in NRLM Equipment From June 1, 2007 Through June 1, 2010

i. Use of a Fuel Marker in Heating Oil

To prevent shifting heating oil into the NRLM market, we proposed that a fuel marker be added to heating oil at the refinery gate. We proposed that the presence of the marker required in heating oil would be strictly prohibited in NRLM diesel fuel. As noted earlier, this approach is similar to red dye requirements for high sulfur diesel fuel that were implemented in 1993 to prevent its use as highway diesel fuel subject to the then applicable 500 ppm sulfur standard.

We proposed that the marker be added at the refinery gate rather than at the terminal for several reasons. First, this seemed to be the most efficient and lowest cost option for addition of the marker given that the number of terminals is far greater than the number of refineries.[113] Second, requiring that the marker be present in heating oil when it is introduced into the distribution system would ensure that we could differentiate high sulfur small refiner and credit fuel from heating oil at any point in the system. This approach would provide good assurance that the inability to use fuel sulfur content to differentiate heating oil from high sulfur NRLM diesel fuel produced under the small refiner and credit provisions in today's rule (effective until June 1, 2010) would not provide an opportunity to mask the potential use of heating oil in NRLM equipment. Providing such assurance is an essential element to enable the implementation of the small refiner and credit provisions in today's rule. Lastly, under the proposed baseline approach, there was no other way to ensure that heating oil was not shifted into the NRLM diesel fuel pool during distribution from the refinery/importer to the terminal.

We received numerous comments that the upstream addition of the proposed marker to heating oil would raise significant concerns that the marker

[112] This highway diesel fuel would meet the currently-applicable 500 ppm sulfur standard for highway diesel fuel.

[113] Additional injection equipment will be required to inject the heating oil marker.

might contaminate jet fuel. Commenters stated that this would represent a substantial safety concern unless the proposed marker was proven not to adversely impact the quality of jet fuel and the operation of jet engines.

The designate and track approach described above for 500 ppm sulfur NRLM diesel fuel, however, also provides an effective means to address concerns about the use of the fuel marker. By extending the designate and track approach to high sulfur NRLM diesel fuel and heating oil, these otherwise identical fuel grades can be tracked down to the terminal, and the marker then can be added at the terminal instead of at the refinery gate. Going beyond the terminal with designate and track is not feasible give the breadth and nature of entities involved.[114] As a result, the marker is still required downstream of the terminal. However, shifting the point of marker addition downstream to the terminal should eliminate any significant opportunity for jet fuel contamination. Subsequent comments and discussions appear to have confirmed this.[115] EPA will continue to work with other federal agencies, including FAA and DoD, and to follow ongoing research and studies regarding the effect of dyes and markers on jet fuel, particularly potential contamination that could have an adverse impact on the safe operation of aircraft. We will keep abreast of the ASTM, CRC, FAA, IRS, and EU activities regarding the evaluation of the use of SY–124 and commit to a review of our use of SY–124 under today's rule based on these findings. If alternative markers are identified that do not raise concerns regarding the potential contamination of jet fuel, we will initiate a rulemaking to evaluate the use of one of these markers in place of SY–124.[116]

We also received a number of comments expressing concern over the inability of the proposed marker to be detected using the standard simple test used today to detect contamination with red dye.[117] The marker finalized by today's rule does not provide visual evidence of its presence. However, if the marker is added at the terminal it will only be present in heating oil when red dye is also present. The fact that heating oil will be dyed red pursuant to IRS requirements before it leaves the terminal will enable jet fuel distributors to continue to use the "white bucket test" to detect heating oil contamination, and hence marker contamination of jet fuel. Today's rule also includes a stand-alone requirement that any fuel to which the fuel marker is added must also contain visible evidence of red dye.[118]

ii. Provisions To Ensure Heating Oil Is Not Used in NRLM Equipment in the Northeast and Mid-Atlantic

In the Northeast, heating oil will continue to be distributed in significant quantities after implementation of the NRLM diesel fuel program. Discussions with terminal operators in the Northeast, and other representatives of heating oil users and distributors, revealed concerns that the proposed heating oil marker requirement would represent a substantial new burden on terminal operators and users of heating oil. Terminal operators stated that the cost of installing new injection equipment would be burdensome, and that the cost of the marker itself would be significant given the large volume of heating oil used in the Northeast. They also stated that they did not expect any small refiner or credit fuel to be used in the Northeast, and that consequently, the marker requirement was not needed in this area. They suggested that if we prohibited the sale of small refiner and credit fuel in PADD I, this area could be exempted from the heating oil marker requirement.

We evaluated the viability of avoiding the heating oil marker requirement in portions of PADD I and instead enforcing the NRLM diesel fuel standards on the basis of sulfur content alone. The heating oil marker is needed to ensure that heating oil is not sold into the NRLM market as high sulfur NRLM fuel. The marker is needed only if high sulfur NRLM fuels will otherwise be in the market. High sulfur NRLM fuel can be produced under the small refiner and credit provisions, and through the generation of high sulfur NRLM in the distribution system from the downgrading of 500 ppm sulfur NRLM. In evaluating the feasibility of avoiding the heating oil marker, EPA therefore focused on determining the likely production and marketing of these high sulfur NRLM fuels in portions of PADD I in this time frame.

We held in-depth discussions with organizations representing refiners, pipelines, and terminal operators to evaluate this issue. Representatives of non-small refiners including API and NPRA stated that being precluded from selling sulfur credit fuel in the Northeast and Mid-Atlantic would not significantly reduce the intended benefits to refiners of the credit provisions in today's rule. We also spoke with small refiner representatives of and the specific small refiners whose marketing area might include the Northeast and Mid-Atlantic and found that in fact, small refiners were not expected to market fuel in this area. Finally, we evaluated the current and likely future practices in the Northeast and Mid-Atlantic areas for the sale of downgraded fuel generated in the distribution system. We found that this downgraded diesel fuel could easily continue to be sold in the very large and ubiquitous heating oil market that is expected to continue to exist in this region. This avoids any need for additional storage or tankage for both high sulfur and low sulfur NRLM fuels, and fits into the pre-existing market structure for heating oil.

Consequently, unlike the rest of the country, there was little expected need to maintain a high sulfur NRLM market in this part of the country as an outlet for small refiner, credit, or off-specification, downgraded diesel fuel. Based on this input, we concluded that codifying this expected practice and making it enforceable, *i.e.* not allowing high sulfur fuel to be marketed as NRLM in this area of the country, would be consistent with the current distribution practices in this area of the country and that the potential impact of taking such an approach on the flexibility offered in the program would be minimal or nonexistent. If we codified it we would no longer need the marker requirement, and the resulting benefits and cost savings to terminals would be substantial. The approach would also simplify and strengthen the enforcement of today's sulfur requirements in this area by allowing EPA to enforce the NRLM standards simply based on the measurement of the sulfur content of the fuel. There would be little expected impact on the environment as this is not expected to change the amount of high sulfur fuel produced from small refiners, credit usage, or downgrade in the distribution system, only the market into which it is sold.

[114] Including every end-user of heating oil.

[115] Letter to Paul Machiele, EPA, from James Thomas, American Society for Testing and Materials (ASTM), entitled "Withdrawal of ASTM Request," January 19, 2004. In this letter ASTM withdraws its request for a postponement of the finalization of the heating oil marker requirements in today's rule. *See* section V.E regarding the selection of the heating oil marker required in today's rule.

[116] *See* section VIII.H. of today's preamble.

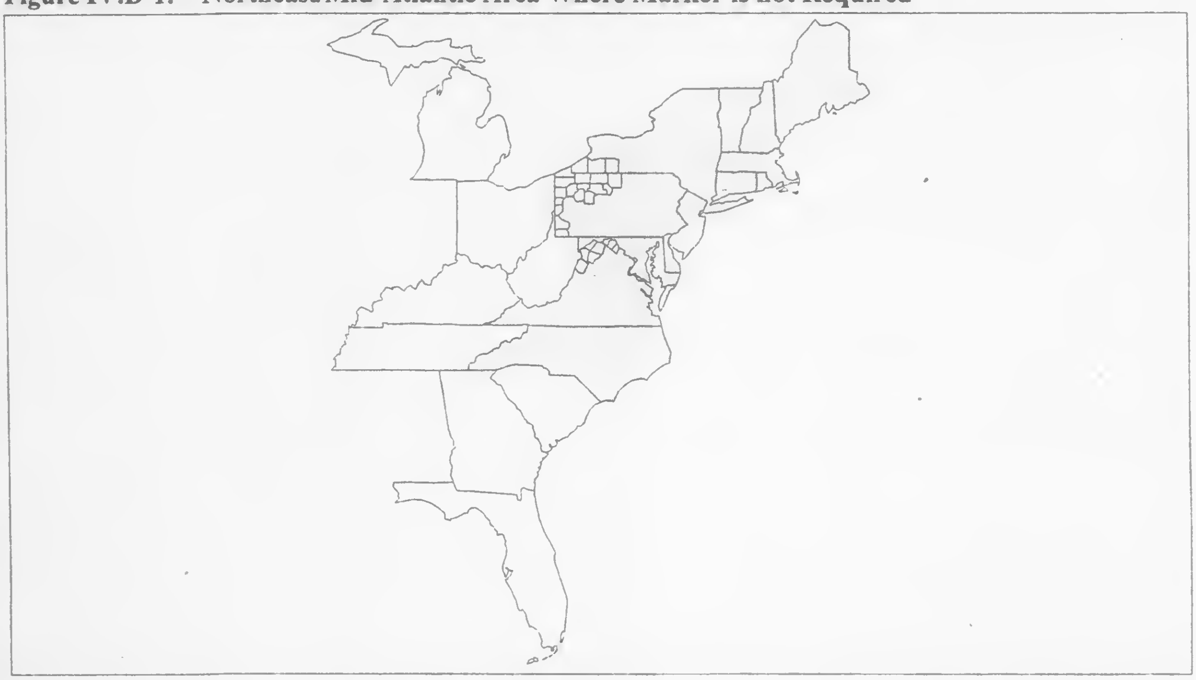
[117] To test for contamination, jet fuel marketers typically fill a white five gallon bucket with jet fuel. The presence of a pink tinge to the light straw colored jet fuel indicates that the fuel has been contaminated with fuel that contains red dye.

[118] If IRS amends its red dye requirements, EPA will also seriously consider amending the fuel marker and associated red dye requirements contained in today's rule. *See* section V.E. of today's preamble.

In deciding which parts of PADD I to use this enforcement mechanism, we attempted to minimize the number of terminals that would need to install new injection equipment and the amount of heating oil that would need to be marked, while preserving the benefits of the small refiner and credit fuel provisions in today's rule to the maximum extent possible. To assess the placement of the boundary for the Northeast/Mid-Atlantic area where the marker requirement was waived, we evaluated the magnitude of heating oil demand by state (*see* chapter 5 of the RIA), solicited input from the potentially affected parties, evaluated the area supplied by the pipeline distribution systems that are expected to continue to ship heating oil after the implementation of today's rule, evaluated the locations of terminals that are likely to receive bulk shipments of heating oil, evaluated the distribution area of small refiner(s) for high sulfur NRLM diesel fuel, and reviewed heating oil use levels in areas that will have access to bulk shipments of heating oil. Based on our assessment we concluded that defining the Northeast/Mid-Atlantic area as described below would best achieve our goals.[119] In most cases, whole states in PADD 1 were assigned to this "Northeast/Mid-Atlantic" area. This decision was primarily based on the continued high level of heating oil use projected in these states and the lack of significant concern regarding the elimination of the program's flexibilities to produce high sulfur NRLM diesel fuel in these states. A few counties in Eastern West Virginia were also assigned to the Northeast/Mid-Atlantic area based on supply patterns in the area. On the other hand, a number of counties in Western New York and Pennsylvania were not assigned to the Northeast/Mid-Atlantic area due to the need to maintain flexibilities for refiners serving this area.

In summary, the areas excluded from the marker requirement and where the sale of NRLM diesel fuel produced or imported under the credit and hardship provisions or from the downstream downgrade provisions of today's rule is prohibited are: North Carolina, Virginia, Maryland, Delaware, New Jersey, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, Maine, Washington DC, New York (except for the counties of Chautauqua, Cattaraugus, and Allegany), Pennsylvania (except for the counties of Erie, Warren, Mc Kean, Potter, Cameron, Elk, Jefferson, Clarion, Forest, Venango, Mercer, Crawford, Lawrence, Beaver, Washington, and Greene), and the eight eastern-most counties in West Virginia (namely: Jefferson, Berkeley, Morgan, Hampshire, Mineral, Hardy, Grant, and Pendleton). The Northeast/Mid-Atlantic Area is illustrated in the following figure:

Figure IV.D-1. – Northeast/Mid-Atlantic Area Where Marker is not Required



As discussed in section IV.D.2 below, the marker requirement for 500 ppm sulfur LM diesel fuel that will be effective outside of this Northeast/Mid-Atlantic area and Alaska from June 1, 2010, through May 31, 2012, was not a significant factor in our evaluation of how to define the boundary of the Northeast/Mid-Atlantic area. We expect that locomotive and marine diesel fuel subject to the marker requirements will primarily be distributed via segregated pathways from a limited number of refineries. Therefore, a significant number of terminals will not need to handle LM diesel fuel that is subject to the marker requirement. Thus, the potential cost of installing injection

[119] *See* chapter V of the RIA for a detailed discussion of the analysis which supports our definition of the Northeast/Mid-Atlantic areas where the marker requirement is waived. *See* section VI of today's preamble and chapter VII of the RIA for a discussion of the costs of the heating oil marker requirements finalized by today's rule.

equipment to add the marker to 500 ppm sulfur LM diesel fuel which is subject to the marker requirement will be limited to only a few refineries and terminals (*i.e.* approximately 15, *see* section VI.A of today's preamble).

In all areas of the country other than the Northeast/Mid-Atlantic area shown in figure IV.D–1 (and Alaska as discussed below), heating oil, and high sulfur NRLM diesel fuel will be designated at the refinery or importer and tracked through the distribution system to the terminal. From June 1, 2010, through May 31, 2012, 500 ppm sulfur LM diesel fuel and 500 ppm nonroad diesel fuel must also be designated at the refinery or importer and tracked through the distribution system to the terminal outside of the Northeast/Mid-Atlantic area and Alaska. The specified fuel marker (*see* section V.E of this preamble) must be added to heating oil distributed from all terminals located outside of the Northeast/Mid-Atlantic area defined above and Alaska. The same fuel marker must also be added to 500 ppm sulfur LM diesel fuel produced at a refinery or imported that is distributed from terminals located outside of the Northeast/Mid-Atlantic area and Alaska from June 1, 2010, through May 31, 2012. This includes all heating oil and the subject 500 ppm sulfur LM diesel fuel distributed from terminals outside of the Northeast/Mid-Atlantic area regardless of whether the fuel is delivered to a retailer, wholesale purchaser-consumer, or end-user located inside or outside of the Northeast/Mid-Atlantic area.

Terminals inside the Northeast/Mid-Atlantic area are exempted from the fuel marker requirements in today's rule, but only for the volume of heating oil and 500 ppm sulfur LM diesel fuel subject to the marker requirements that is used by wholesale-purchaser-consumers and end-users that are located inside the Northeast/Mid-Atlantic area. Any heating oil and subject 500 ppm sulfur LM diesel fuel distributed from terminals inside the Northeast/Mid-Atlantic area to a retailer, wholesale-purchaser-consumer, or end-user that is located outside of the Northeast/Mid-Atlantic area must be marked.

Terminal operators do not often distribute fuel to retailers, wholesale-purchaser-consumers, and end-users directly. This task is frequently accomplished by "jobbers" who pick up large tank truck loads of fuel from the terminal for delivery to their retailer and wholesale-purchaser-consumer customers, "heating oil dealers" who pick up fuel from a terminal using a smaller capacity tank truck (often referred to as a tank wagon) for direct delivery to heating oil users, and by bulk plant operators. Bulk plant operators pick up fuel from terminals as described above. However, since they maintain their own bulk fuel storage facilities, they have the choice of storing the fuel at their facility prior to eventual delivery to their customers. Under the provisions of today's rule, as long as a bulk plant only receives heating oil to which the marker has already been added, it does not have to register, keep records, or report. However, if it chooses to receive any unmarked heating oil, then it will be treated the same as a large terminal under the provisions of today's final rule. We do not expect that bulk plants will handle LM diesel fuel to a significant degree. For bulk plant operators that might handle LM diesel fuel, today's rule provides that as long as a bulk plant does not receive any 500 ppm sulfur LM diesel fuel which is required to be marked under today's rule, but which has not yet been marked, it does not have to register, keep records, or report. However, if it chooses to receive any unmarked 500 ppm sulfur LM diesel fuel which is subject to the marker requirements under today's rule, then it will be treated the same as a large terminal under the provisions of today's final rule.

Any party that transports bulk quantities of heating oil solely to the Northeast/Mid-Atlantic area or within this area is not subject to the designate and track requirements for heating oil described below. Similarly, any party that transports bulk quantities of 500 ppm sulfur LM diesel fuel solely to the Northeast/Mid-Atlantic area or within this area is not subject to the designate and track requirements for LM diesel fuel. However, any high sulfur fuel distributed from inside the Northeast/Mid-Atlantic area to outside of the Northeast/Mid-Atlantic area must be designated as heating oil by the party responsible for the transfer and must be marked. Likewise, any 500 ppm sulfur LM diesel fuel distributed from inside the Northeast/Mid-Atlantic area from June 1, 2010, through May 31, 2012, must be designated as 500 ppm sulfur LM diesel fuel by the party responsible for the transfer and must be marked.

Entities who are required to inject marker into heating oil must maintain records of the volume of marker used in heating oil, and the volume of heating oil distributed over the compliance period. Entities that are required to inject marker into 500 ppm sulfur LM diesel fuel must maintain records of the volume of marker used in 500 ppm sulfur LM diesel fuel, and the volume of 500 ppm sulfur LM diesel that is required to be marked which is distributed over the compliance period. These records must demonstrate that the prescribed marker concentration was present in the heating oil and the 500 ppm sulfur LM diesel fuel subject to the marker requirement that they discharged.

iii. State of Alaska

Although the fuel marker facilitates the enforcement of the NRLM diesel fuel sulfur standards by distinguishing it from heating oil, as described above, we are not requiring use in Alaska. Unlike the situation in the Northeast and Mid-Atlantic area, however, we are not prohibiting the production of high sulfur NRLM diesel fuel after 2007, and 500 ppm nonroad diesel fuel from after 2010 by small refiners in Alaska. While such a prohibition in the Northeast/Mid-Atlantic area does not impact small refiners, flexibility for small refiners is expected to be important in Alaska. Thus, we need to preserve the flexibility for high sulfur NRLM diesel fuel in Alaska for small refiners along with eliminating the marker. The program must therefore provide another means of enforcing the NRLM diesel fuel sulfur standards without eliminating a small refiner's ability to produce and distribute high sulfur NRLM diesel fuel.

Under today's program we are finalizing a provision that will allow flexibility for small refiners to delay compliance with the NRLM diesel fuel sulfur standards as discussed in section IV.B. Small refiners in Alaska may avail themselves of this option provided that the refiner first obtains approval from the administrator for a compliance plan. The plan must at a minimum show the following information:

(1) How they will segregate its fuel through to end-users;

(2) How they will segregate its fuels from other grades and other refiners' fuels; and

(3) All end-users to whom the fuel is sold as well as the fuel volumes.

End-users who receive the fuel must retain records of all fuel shipments to demonstrate that no heating oil was used in NRLM diesel equipment and that no 500 ppm sulfur LM diesel was used in nonroad equipment. In order to limit the potential sources of fuel not meeting the sulfur standard, constrain the number of end-users who may legitimately have higher sulfur fuel in their NRLM diesel equipment, and thus maintain the overall program's enforceability, we are not finalizing the other provisions that allow for higher sulfur fuel to be produced and/or distributed in Alaska (*i.e.*, credit, transmix processor, or downstream distribution system provisions). In this regard, Alaska is treated in the same manner as the Northeast/Mid-Atlantic area.

c. Updating the Highway Program's Anti-Downgrade Requirements

Under the highway diesel fuel program, each entity in the distribution system may downgrade a maximum of 20 percent of the 15 ppm sulfur highway diesel fuel it receives to 500 ppm sulfur highway diesel fuel. However, there was no limit on the volume of 15 ppm sulfur highway diesel fuel that could be downgraded to NRLM diesel fuel. Prior to today's rule, this was appropriate because the sulfur content of NRLM diesel fuel was uncontrolled, and hence once 15 ppm sulfur highway diesel fuel was downgraded to NRLM diesel fuel such fuel could not be used in the 500 ppm sulfur highway diesel market. The implementation of today's 500 ppm sulfur standard for NRLM diesel fuel, however, means that 15 ppm sulfur highway fuel downgraded to 500 ppm sulfur NRLM diesel fuel potentially could be shifted into the highway market. This could undermine the benefits of the highway program for the reasons described previously. To prevent this situation, we proposed that the anti-downgrading requirements under the highway diesel program would also apply to the downgrading of 15 ppm sulfur highway diesel fuel to 500 ppm sulfur NRLM diesel fuel. We received comments from refiners and fuel distributors that such a limitation would restrict their ability to supply the NRLM diesel market, particularly in areas where refiners plan to supply only 15 ppm sulfur diesel fuel for both the highway and NRLM markets.

Putting in place the designate and track provisions allows 500 ppm sulfur highway and 500 ppm sulfur NRLM diesel fuel to be tracked separately. This enables the anti-downgrading requirements to only apply to the downgrading of 15 ppm sulfur highway diesel fuel to 500 ppm sulfur highway fuel as originally required in the 2007 highway final rule. In the context of the designate and track requirements in today's rule, the highway program's anti-downgrading provisions are clarified as described below. Similar to the approach described above regarding the prevention of the use of 500 ppm sulfur NRLM diesel fuel in the highway market, each custodian of 15 ppm sulfur No. 2 highway diesel fuel must maintain records that demonstrate their compliance with the highway program's anti-downgrade requirements. The anti-downgrading requirements do not apply to 15 ppm sulfur No 1, diesel fuel. Such fuel will be manufactured for wintertime blending to improve diesel cold flow properties. In a number of areas we expect that 15 ppm sulfur No. 1 fuel will be the only No.1 fuel available for winterizing highway and NRLM diesel fuel, and heating oil. Therefore, applying the anti-downgrading requirements to 15 ppm sulfur No. 1 fuel would be unnecessary to maintain the availability of 15 ppm sulfur highway diesel fuel, and would interfere with its intended use in the range of No. 2 fuels.

From October 1, 2006, through May 31, 2010, all fuel distributors downstream of the refiner or import facility must satisfy one of four criteria as outlined in 40 CFR 80.598 of today's regulation to demonstrate compliance with the highway program's anti-downgrading requirements. These criteria are based on the designate and track system for different grades of fuel through the distribution system. The first criteria is the simplest and most straightforward, with the least record keeping burden. It merely tracks a facility's No. 2 15 ppm sulfur highway diesel volume receipts and deliveries and requires the deliveries to be at least 80 percent of the receipts. Since the anti-downgrading provisions were implemented to protect against intentional downgrading and not to limit downgrading that would occur in the normal distribution of 15 ppm sulfur fuel, we anticipate that most facilities will be able to easily meet this simple criteria.

The second criteria tracks a facility's receipts and distribution of both No. 2 15 ppm sulfur fuel and No.2 500 ppm sulfur highway diesel fuel, and limits deliveries of No. 2 500 ppm sulfur highway diesel fuel to no more than what was received plus 20 percent of the No. 2 15 ppm sulfur highway diesel fuel volume received. This allows more flexibility than the first criteria by not constraining downgrades to NRLM diesel fuel or heating oil, but does so by requiring tracking and records of volumes of No. 2 15 ppm sulfur highway diesel fuel received and the products to which it is downgraded.

The third and fourth criteria provide even more flexibility, especially for wintertime blending of No. 1 15 ppm sulfur highway diesel fuel, and also for any temporary shifts that might occur between NRLM diesel fuel and highway diesel fuel markets from 2007–2010. However, a facility will have to meet more extensive criteria to demonstrate compliance.

Today's final rule does not change any other aspects of the anti-downgrading provisions finalized in the 2007 highway diesel final rule, such as the provisions unique to fuel retailers.

2. Requirements During the Second Step of Today's Sulfur Control Program

Beginning June 1, 2010, all NR diesel fuel and beginning June 1, 2012 all LM diesel fuel produced or imported must meet a 15 ppm sulfur standard except for fuel manufactured under the credit and small refiner provisions in today's rule. This credit and small refiner diesel fuel must meet a 500 ppm sulfur level. From June 1, 2010 to June 1, 2012, all LM diesel fuel must meet a 500 ppm sulfur standard. Today's rule also allows 500 ppm sulfur diesel fuel generated in the pipeline distribution system to be used in NRLM equipment through May 31, 2014 [120] and in locomotive and marine equipment thereafter. After May 31, 2014, the credit and small refiner provisions expire.

We proposed that once refiners were no longer able to produce 500 ppm sulfur diesel fuel for use in nonroad engines and such fuel had a few months to work its way through the distribution system, that 500 ppm sulfur diesel fuel could no longer be used in nonroad equipment. Today's rule adopts this proposed prohibition. Although today's rule extends the 15 ppm sulfur nonroad diesel standard to locomotive and marine diesel fuel, we have elected not to extend the prohibition against the use of 500 ppm sulfur diesel fuel in locomotive and marine equipment after refiners and importers are no longer allowed to produce/import such fuel. Diesel fuel with a maximum sulfur concentration of 500 ppm that is generated in the pipeline distribution system can continue to be used in locomotive and marine equipment after June 1, 2014, as discussed in section IV.A above.

Providing for the continued use of 500 ppm sulfur diesel fuel in NRLM equipment through May 31, 2014, means that without adequate controls similar to those under the first step of today's program, a refiner could manufacture 500 ppm sulfur diesel fuel ostensibly for use as heating oil which could actually be sold downstream into the NRLM market through May 31, 2014. Similarly, the continued use of 500 ppm fuel in locomotive and marine engines after May 31, 2014, means that without adequate controls, a refiner could continue to manufacture 500 ppm sulfur diesel fuel ostensibly for use as heating oil which could actually be sold

[120] The use of 500 ppm fuel in nonroad equipment is restricted to 2011 model year and earlier equipment.

downstream into the locomotive and marine market indefinitely. To prevent this possibility, we have elected to continue the designate and track and marker requirements for heating oil applicable under the first step of today's program indefinitely with some simplifications. It is a significantly smaller program during the second step, since only heating oil needs to be tracked, and we expect that by then very little heating oil will be produced for sale outside of the Northeast/Mid-Atlantic area. Consistent with the approach taken during the first step of today's program, these designate and track provisions would not be applicable in the Northeast/Mid-Atlantic area or Alaska, since the flexibility to sell greater than 15 ppm sulfur diesel fuel into the NRLM market there does not exist under this final rule.[121] Any diesel fuel with a sulfur content greater than 500 ppm beginning June 1, 2007, any NR diesel fuel with greater than 15 ppm sulfur beginning June 1, 2010, and any LM diesel fuel with greater than 15 ppm sulfur beginning June 1, 2012 in the Northeast/Mid-Atlantic area can only be sold as heating oil, and if shipped outside of the Northeast/Mid-Atlantic area must be marked as heating oil.

While today's rule does not contain an end date for the downstream distribution of 500 ppm sulfur locomotive and marine fuel, we will review the appropriateness of allowing this flexibility based on experience gained from implementation of the 15 ppm sulfur NRLM diesel fuel standard. We expect to conduct such an evaluation in 2011. Were we to discontinue the downstream provision for downgraded fuel, we would also evaluate discontinuing the designate and track and marker requirements for heating oil, as is the case now for the Northeast/Mid-Atlantic area.

Providing for the continued production and import of 500 ppm sulfur LM diesel fuel from June 1, 2010 to June 1, 2012 means that without adequate controls similar to those under the first step of today's program, a refiner could manufacture 500 ppm sulfur diesel fuel ostensibly for use as LM diesel fuel which could actually be sold downstream into the NR market. To prevent this possibility, we have adopted designate and track and marker requirements similar to those applicable to heating oil under the first step of today's program. For these two years, 500 ppm sulfur NR and LM diesel fuel would be tracked, and the 500 ppm sulfur LM fuel would be marked in the same manner as heating oil. The same provisions that apply to marking of heating oil, such as the Northeast/Mid-Atlantic area, would also apply to the marking of 500 ppm sulfur LM fuel. The tracking and marking provisions would not apply to any 15 ppm sulfur LM diesel fuel.

3. Summary of the Designate and Track Requirements

The designate and track program requires refiners and importers to designate the volumes of diesel fuel they produce and/or import. Refiners/importers will identify whether their diesel fuel is highway or NRLM and the applicable sulfur level. They may then mix and fungibly ship highway and NRLM diesel fuels that meet the same sulfur specification without dyeing their NRLM diesel fuel at the refinery gate. The volume designations will follow the fuel through the distribution system with limits placed on the ability of downstream parties to change the designation. These limits are designed to restrict the inappropriate sale of 500 ppm sulfur NRLM diesel fuel into the highway market; from 2007 to 2010, the inappropriate sale of 500 ppm sulfur LM diesel fuel into the 500 ppm sulfur NR market from 2010 to 2012; and the inappropriate sale of heating oil into the NRLM market. The designate and track approach includes record keeping and reporting requirements for all parties in the fuel distribution system, associated with tracking designated fuel volumes through each custodian in the distribution chain until the fuel exits the terminal. The program also includes enforcement and compliance assurance provisions to enable the Agency to rapidly and accurately review for discrepancies the large volume of data collected on fuel volume hand-offs.

a. Registration

Each entity in the fuel distribution system, up through and including the point where fuel is loaded onto trucks for distribution to retailers or wholesale purchaser-consumers, must register each of its facilities with EPA no later than December 31, 2005, or six months prior to commencement of producing, importing, generating, or distributing any designated diesel fuel.[122] A facility is defined as the physical location(s) where a party has custody of designated fuel, from when it was produced, imported, or received from one party to when it is delivered to another party. The definition also include mobile components, such as the vessels in a barge facility. Examples of facilities include refineries, import terminals, pipelines, terminals, bulk plants, and barge systems. Where the same entity owns and operates a series of locations in the distribution system (*e.g.*, refiner to pipeline to terminal), it may choose to register them as a single aggregated facility, provided the entity maintains custody of the fuel throughout the facility. However, if the aggregated facility includes a refinery, then it may not receive any diesel fuel from another entity at any place within the aggregated facility. Under this approach, a pipeline could be treated as one facility from the point where it receives fuel to the point where it either delivers it to a terminal, or into a tank truck after passing through their terminal. The choice made by the entity to treat these places as a single facility or separate facilities may not change during any applicable compliance period. These same definitions for facility will apply for both the designate and track provisions, as well as the anti-downgrading provisions of the highway rule. Therefore, if a proprietary system chooses to aggregate into one facility for purposes of the designate and track provisions, it will also be treated as one facility for determining compliance with the 20 percent anti-downgrading limit of the highway rule. EPA will provide a unique registration number to each custodial facility of designated fuels. In addition, EPA intends to work with industry subsequent to this final rule to provide guidance regarding facility boundary and aggregation decisions that will address the many unique situations.

The designation provisions described below require refiners and importers to designate all distillates they produce or import consistent with the production and end-use requirements in today's rule. These designations serve as the foundation upon which the fuel distributors are able to properly track, designate, redesignate, and label the fuel they receive.

b. Designation by Refiners and Importers

i. Designation of 500 ppm and 15 ppm Sulfur Diesel Fuel

From June 1, 2006, through May 31, 2010, any refiner[123] or importer that

[121] Unless, in the case of Alaska, the refiner segregates its fuel through to the end user as discussed in section IV.D.1.b.ii.

[122] This requirement also applies to parties inside of the Northeast/Mid-Atlantic area who handle heating oil.

[123] Transmix operators that produce diesel fuel from transmix and terminal operators that produce from segregated interface will be treated as a refiner

Continued

produces or imports 15 ppm sulfur diesel fuel, and/or 500 ppm sulfur diesel fuel must designate all batches of such fuel as one of the following. The purpose of this designation requirement is to ensure that 500 ppm sulfur NRLM diesel fuel is not shifted into the highway market, and to evaluate compliance with the highway program's anti-downgrade requirements.

- 15 ppm sulfur No. 2 highway diesel fuel;
- 15 ppm sulfur No. 1 highway diesel fuel;
- 500 ppm sulfur No. 2 highway diesel fuel;
- 500 ppm sulfur No. 1 highway diesel fuel;
- 500 ppm sulfur No. 2 NRLM diesel fuel;
- 500 ppm sulfur No. 1 NRLM diesel fuel;
- 500 ppm sulfur jet fuel; or
- 500 ppm sulfur kerosene.

The start date for these requirements coincides with the start date for the early credit program under today's final rule, and the start date for the highway diesel program for the purposes of anti-downgrading. The end date for these requirements coincides with the end date for the highway program's Temporary Compliance Option and today's NRLM diesel fuel early credit program.

Any batch of 15 ppm or 500 ppm No. 1 diesel fuel which is also suitable for use as kerosene or jet fuel (referred to as dual-purpose kerosene) may be considered kerosene or jet fuel and need not be designated as highway or NRLM diesel fuel, even if it may later be blended into highway or NRLM diesel fuel downstream of the refinery to improve the cold-flow properties of the fuel. Upon such blending, the kerosene or jet fuel takes on the designation of the diesel fuel into which it was blended. We expect refiners and importers will elect to designate all of their 15 ppm sulfur No. 1 diesel fuel as highway fuel, since this will aid in their compliance with the highway program's 80/20 highway fuel production requirement. Designation as highway diesel fuel by the refiner will also help avoid downstream blending from causing a violation by the downstream party under the tracking and compliance calculations finalized today. We also expect that refiners and importers will elect to designate their 500 ppm sulfur No. 1 fuel as kerosene or jet fuel since this will be the predominant use for such fuel, and designating it as highway would hinder their compliance with the 80/20 highway requirements. As with 15 ppm sulfur kerosene or jet fuel, downstream parties would later redesignate it as highway or NRLM diesel fuel if blended in or used for these purposes. Any 500 ppm sulfur diesel fuel containing visible evidence of red dye must be designated as NRLM diesel fuel or heating oil unless it is tax exempt highway diesel fuel (*e.g.*, fuel for use in school buses or certain municipal fleets).

for the purposes of compliance with these requirements.

The reported volumes of designated fuels must be the volumes delivered to the first downstream party. This is typically a pipeline facility, a marine barge/tanker loading dock that accepts product from a refiner/importer, or the refiner's/importer's truck loading rack. This is consistent with normal business practices. Refiners, importers, and transmix processors are not required to add red dye to NRLM diesel fuel unless the fuel is distributed over their truck loading rack such that the IRS requires the addition of red dye for the assessment of taxes.

Fuel designated by a refiner or importer as highway diesel fuel must comply with the highway program's 80/20 requirement for 15 ppm/500 ppm sulfur highway diesel fuel. The volume of fuel designated as NRLM early credit fuel must be consistent with the credit provisions in today's rule. Since highway diesel fuel volumes are determined at the point of delivery from the refiner/importer to another party, the anti-downgrade requirements do not apply to refiners and importers. Under the highway diesel fuel program, refiners that are required to produce 100 percent of their highway diesel fuel to a 15 ppm sulfur standard are provided with an allowance to deliver a small percentage of 500 ppm sulfur diesel fuel to the pipeline (*e.g.*, small refiners and GPA refiners who exercise an option under the 2007 highway rule to delay compliance with gasoline sulfur standards). This allowance is provided because a small volume of "line-wash" is typically generated in the feed line from the refiner's facility to the pipeline. This line-wash will often be suitable for use as 500 ppm sulfur highway diesel fuel. Under the provisions of the highway rule this line-wash could have been excluded from compliance with the 15 ppm standard if the refiner accounted for their production volume prior to shipment. However, in this rule, all volume-related requirements are keyed to the volume actually delivered. As a result of this change in the point of fuel volume measurement (delivered versus produced), we are amending the highway diesel fuel program requirements such that refiner who was previously required to produce 100 percent of its highway diesel fuel to the 15 ppm sulfur standard may now produce 95 percent to the 15 ppm sulfur standard (in order to avail itself of the extended gasoline sulfur interim standards).

ii. Designation of High Sulfur NRLM Diesel Fuel, Heating Oil, and Jet Fuel/Kerosene

From June 1, 2007 through May 31, 2010, any refiner, or importer not located in the Northeast/Mid-Atlantic area or Alaska, that produces or imports unmarked high sulfur distillate fuel must designate all batches of such fuel as one of the following: heating oil, high sulfur NRLM diesel fuel, or jet fuel/kerosene. Any heating oil distributed from a refiner's or importer's rack not located in the Northeast/Mid-Atlantic area or Alaska must contain the designated marker and red dye. Any heating oil distributed from a refiner/importer rack inside of the Northeast/Mid-Atlantic area or Alaska is exempted from the marker requirement except any heating oil that is delivered outside the Northeast/Mid-Atlantic area must be marked.

As discussed previously, 500 ppm sulfur diesel fuel may be used in NRLM equipment through May 31, 2014 and in locomotive and marine equipment thereafter. Therefore, designate and track provisions for heating oil will be needed to ensure that heating oil is not shifted into the NRLM market from June 1, 2007 through May 31, 2014, and to the locomotive and marine market thereafter. Consequently, from June 1, 2010 through May 31, 2014, refiners and importers must continue to designate any heating oil they produce as such as well as any 500 ppm sulfur NRLM diesel fuel produced under the small refiner, transmix/segregated interface, and credit provisions.

Beginning June 1, 2014, refiners and importers may no longer produce or import 500 ppm sulfur diesel fuel for use in NRLM equipment. Therefore, beginning June 1, 2014, all diesel fuel with a sulfur level greater than 15 ppm must be designated as heating oil, jet fuel, or kerosene. The one exception to this is transmix processors and terminals acting as refiners which will be permitted to produce 500 ppm sulfur diesel fuel for use in locomotive and marine equipment from transmix and segregated interface.

iii. Designation of 500 ppm NR and 500 ppm LM Sulfur Diesel Fuel

From June 1, 2010, through May 31, 2012, any refiner or importer that produces or imports 500 ppm sulfur NR diesel fuel (small refiner and credit) and/or 500 ppm sulfur LM diesel fuel must designate all batches of such fuel. The purpose of this designation requirement is to ensure that 500 ppm sulfur LM diesel fuel is not shifted into the NR market. Any 500 ppm sulfur LM diesel fuel distributed from a refiner's or importer's rack not located in the Northeast/Mid-Atlantic area or Alaska must contain the designated marker and red dye, along with heating oil. Any 500 ppm sulfur LM diesel fuel distributed from a refiner/importer rack inside of the Northeast/Mid-Atlantic area or Alaska is exempted from the marker requirement except any 500 ppm sulfur LM fuel that is delivered outside the Northeast/Mid-Atlantic area must be marked.

c. Designation and Tracking Requirements Downstream of the Refinery or Importer

The result of the refiner/importer designation provisions is that all of the diesel fuel received by distributors will be clearly and accurately designated. The distributors are then subject to their own designation and tracking requirements. The downstream provisions are designed to ensure that certain fuel shifts do not occur, such as the inappropriate shifting of 500 ppm sulfur NRLM diesel fuel to the highway market, the inappropriate shifting of 500 ppm sulfur LM diesel fuel into the nonroad market, the inappropriate downgrading of 15 ppm sulfur to 500 ppm sulfur highway diesel fuel, and the inappropriate shifting of heating oil to the NRLM market. The downstream provisions are designed to ensure these results in a readily enforceable manner while maximizing downstream flexibility to address changing market conditions.

In general, each time custody of designated fuel is transferred from one facility to another facility, the transferor must designate the fuel and record it's volume. The party who receives custody must record the same information, to ensure that each party relies on the same designation and volume for its own compliance purposes. This process occurs each time custody of diesel fuel is transferred. Each distributor may redesignate fuel while in its custody or when it is delivered, subject to certain basic requirements. First, any re-designation must be accurate. For example, 500 ppm sulfur NRLM diesel fuel can not be redesignated as 15 ppm unless it in fact meets the 15 ppm standard. The sulfur standard applicable to downstream fuel is based on the fuel's designation. Second, there are limits on the fuel volumes that can be redesignated, calculated as a volume balance over a specified compliance period. Specifically, the volumes of 15 ppm and 500 ppm sulfur highway received must be compared to the volumes of these fuels delivered, to ensure that the amount of 15 ppm sulfur highway diesel fuel that is downgraded to 500 ppm sulfur highway diesel fuel complies with the highway program's anti-downgrading requirements. The volumes of 500 ppm sulfur highway and NRLM diesel fuel that a distributor receives must also be compared to the volumes of 500 ppm sulfur highway and NRLM diesel fuel delivered, to ensure that NRLM diesel fuel was not inappropriately transferred to the highway market. The volumes of 500 ppm sulfur NR and LM diesel fuel received must be compared to the volumes of 500 ppm sulfur NR and LM diesel fuel delivered, to ensure that the 500 ppm sulfur LM fuel was not inappropriately transferred to the NR market. In addition, the volumes of heating oil received must be compared to the volumes distributed to ensure it was not inappropriately transferred to the NRLM market. These volume balances are calculated over a compliance period, providing distributor's the day to day flexibility to redesignate fuel based on market conditions, as long as the required volume balance is achieved over the compliance period. Finally, once NRLM diesel fuel is dyed, 500 ppm sulfur LM diesel fuel is marked (2010–2012), or heating oil is marked, the dye and marker may be used to ensure the fuels are not inappropriately shifted to other markets, and the designation, tracking and volume balance requirements are no longer needed; just the PTD, labeling, and record keeping provisions typical of our other fuel regulations (*e.g.*, highway diesel) apply.

In large part, the designate and track provisions are structured to be compatible with the normal business practices currently used by the industry to record and reconcile volume transactions between parties. As such, EPA expects that these downstream provisions can be implemented in a fairly straightforward manner.

i. Designation and Tracking of 500 ppm and 15 ppm Sulfur Diesel Fuel

From June 1, 2006 through May 31, 2010, facilities downstream of the refiner or importer must designate and maintain records of all volumes of fuel designated as 15 ppm sulfur highway diesel fuel, 500 ppm sulfur highway diesel fuel, or 500 ppm sulfur NRLM diesel fuel that they receive and deliver. In many cases, we expect that downstream facilities will not change the designation of 500 ppm sulfur diesel fuel from NRLM diesel fuel to highway while the fuel is in their custody. However, to accommodate fluctuations in the demand for highway-designated versus NRLM-designated 500 ppm sulfur fuel, today's rule allows terminals and other distributors to change the designation of 500 ppm sulfur fuel from NRLM diesel fuel to highway diesel fuel on a daily basis, as long as the required volume balance is achieved over the compliance period.[124] Terminal operators must ensure that the running balance of total highway-designated fuel that they discharged from the beginning of today's program does not exceed the volume of highway fuel that they received since, and had in their possession at the beginning of today's program (adjusted for changes in inventory). This simple one-sided test allows 15 ppm sulfur highway diesel fuel to flow to 500 ppm sulfur highway diesel fuel (subject to anti-downgrading limits), 500 ppm sulfur NRLM diesel fuel, or heating oil. It also allows 500 ppm sulfur highway diesel fuel to flow to NRLM diesel fuel or heating oil. However, the flow of NRLM diesel fuel to highway diesel fuel must first have been offset by shifts from highway to NRLM diesel fuel. In this way we can have assurance that the 500 ppm sulfur fuel sold for highway purposes was in fact produced pursuant to the 80/20 requirements of the highway rule. Since any 500 ppm sulfur diesel fuel in the possession of parties downstream of the refiner at the beginning of today's program will be considered as highway diesel fuel, each custodian will begin today's program with a positive volumetric account balance regarding their input/output of highway-designated 500 ppm sulfur. Conformity with this requirement will be evaluated by EPA at the end of each quarterly compliance period.

In order to accommodate volumetric fluctuations due to such factors as thermal expansion of the fuel, facilities such as pipelines upstream of the terminal can use the same volumetric balance. However, since these facilities typically do not, and should not change designations, the compliance periods can be annual. In addition, to ensure that there are no significant redesignations, we are also requiring that the volume of highway-designated 500 ppm sulfur diesel fuel that a facility

[124] Any party is free to redesignate highway diesel fuel to NRLM diesel fuel or heating oil at any time. The required volume balance does not limit such designations.

discharges from its custody must be no greater than 102 percent of the volume of such fuel that it received during each annual compliance period. All parties downstream of the refiner, importer, or transmix processor also must demonstrate that over any given compliance period, they did not downgrade more than 20 percent of the 15 ppm highway diesel fuel that they received to 500 ppm sulfur highway diesel fuel.

From June 1, 2006 through May 31, 2010, distributors must maintain records regarding each transfer of a designated fuel into and out of their facility on a batch-by-batch basis. These records must include the EPA registration number of the source or recipient facility, and the volume of each designated fuel transfer. However, for transfers of dyed NRLM and highway diesel fuel on which taxes have been assessed, the recipient or source facility need not be specifically identified. In such cases, records must be kept regarding the total volume of dyed and tax assessed fuel that is received, discharged, and in inventory during each compliance period. After May 31, 2010, unique records for these designate and track provisions are no longer required, but the normal records and PTDs must still be kept regarding compliance with the fuel standards.

ii. Designation and Tracking of High Sulfur NRLM Diesel Fuel and Heating Oil

The requirements regarding the designation and tracking of heating oil and high sulfur or 500 ppm sulfur NRLM diesel fuel parallel those regarding the designation and tracking of 500 ppm sulfur highway and NRLM diesel fuel discussed above. However, the requirements described below pertain only to facilities not in the Northeast/Mid-Atlantic area or Alaska, and to facilities inside of the Northeast/Mid-Atlantic area that transport heating oil outside of the Northeast/Mid-Atlantic area.

From June 1, 2007 through May 31, 2010, facilities downstream of the refiner or importer must designate all high sulfur diesel fuel they distribute as NRLM diesel fuel and all heating oil they distribute as heating oil, and must keep records of all volumes of fuel designated as high sulfur NRLM diesel fuel or heating oil. In many cases, we expect that downstream facilities will not change the designation of diesel fuel from heating oil to high sulfur NRLM diesel fuel while the fuel is in their custody. However, today's final rule provides the flexibility to make this change in designation provided that volume balance requirements for high sulfur NRLM diesel fuel are met.

The volume balance for heating oil requires that the volumes of high sulfur NRLM diesel fuel and heating oil received must be compared to the volumes of high sulfur NRLM diesel fuel and heating oil delivered over a compliance period. The volume of high sulfur NRLM diesel fuel may not increase by a greater proportion than the volume of heating oil over a compliance period. There are many reasons why the combined pool of high sulfur fuel will increase in volume such as the inevitable downgrades from 15 ppm and 500 ppm when these fuels are shipped by pipeline. The volume balance allows for this to occur while keeping fuel produced as heating oil from being shifted to NRLM diesel fuel. The volume balance calculation allows high sulfur NRLM diesel fuel and heating oil to increase proportionately, satisfying both needs. As discussed previously, high sulfur NRLM diesel fuel and heating oil compliance will be required on a quarterly basis for terminal facilities that add marker/dye (and are more likely to change designations on a day to day basis), while compliance for other entities (*e.g.*, pipelines) will be on an annual basis. Compliance with the volume balance requirement is determined by comparing volumes received and delivered during that compliance period. There is no need to have a running total volume of high sulfur NRLM diesel fuel delivered from the beginning of the program since we do not expect any party will need to redesignate heating oil to high sulfur NRLM diesel fuel, even on a day-to-day basis. Further, we are not providing any tolerance since sufficient flexibility already exists due to the many sources of downgrade to heating oil.

Facilities must maintain records regarding each transfer of heating oil and high sulfur NRLM diesel fuel that they receive and discharge from June 1, 2007 through May 31, 2010 on a batch-by-batch basis.[125] These records must include the EPA registration number of the source or recipient facility, and the volume of each fuel transfer. However, for transfers of marked heating oil, the recipient or source facility need not be specifically identified. In such cases, records must be kept regarding the total volume of marked heating oil that is received, discharged, and in inventory during each compliance period. For transfers of dyed high sulfur NRLM diesel fuel from a truck loading rack, the specific recipients also do not need to be identified. In such cases, records must be kept regarding the total volume of high sulfur NRLM diesel fuel that is received, discharged, and in inventory during each compliance period.

From June 1, 2010 through May 31, 2014, facilities downstream of the refiner or importer must continue to designate heating oil and any 500 ppm sulfur NRLM diesel fuel that they distribute. Beyond June 1 2014, they must designate 500 ppm sulfur LM diesel fuel in addition to heating oil. Designations for heating oil are subject to the volume balance requirements and records must be kept on the designations.

Beginning June 1, 2010, the volume balance requirement for heating oil is simply that the volume of heating oil may not decrease. As discussed previously, there are many reasons why the volume could increase. Consequently, if the volume decreases it would mean that heating oil is being shifted to NRLM or locomotive and marine uses, thereby allowing refiners to circumvent the NRLM diesel fuel sulfur standards. Given the likely increase in heating oil volume for other reasons, there should be ample flexibility provided with this one-sided test to account for minor variations due to volume swell/shrinkage related to temperature, meter differences, or other causes, so no additional tolerance or flexibility is necessary.

iii. Designation and Tracking of 500 ppm Sulfur NR and LM Diesel Fuel

The requirements regarding the designation and tracking of 500 ppm sulfur NR and LM diesel fuel parallel those regarding the designation and tracking of 500 ppm sulfur highway and NRLM diesel fuel discussed above. However, the requirements described below pertain only to facilities not in the Northeast/Mid-Atlantic area or Alaska, and to facilities inside of the Northeast/Mid-Atlantic area that transport 500 ppm sulfur NR and LM diesel fuel outside of the Northeast/Mid-Atlantic area.

From June 1, 2010 through May 31, 2012, facilities downstream of the refiner or importer must continue to designate 500 ppm sulfur NR and LM diesel fuel that they distribute, and must keep records of all volumes of fuel designated as these fuels. In many cases, we expect that downstream facilities will not change the designation of diesel fuel from 500 ppm sulfur LM to 500 ppm sulfur NR diesel fuel while the fuel is in their custody. However, today's final rule provides the flexibility to make this change in designation provided that volume balance

[125] As discussed in section V, these records must be kept for five years.

requirements for 500 ppm sulfur NR diesel fuel are met.

The volume balance for 500 ppm sulfur NR and LM diesel fuel requires that the volumes of 500 ppm sulfur NR and LM diesel fuel received must be compared to the volumes of 500 ppm sulfur NR and LM diesel fuel delivered over a compliance period. The volume of 500 ppm sulfur NR diesel fuel may not increase by a greater proportion than the volume of 500 ppm sulfur LM diesel fuel over a compliance period. The combined pool of 500 ppm sulfur diesel fuel may increase in volume such as the inevitable downgrades from 15 ppm and 500 ppm sulfur diesel fuel when these fuels are shipped by pipeline. The volume balance allows for this to occur while keeping fuel produced as 500 ppm sulfur LM diesel fuel from being shifted to NR fuel. The volume balance calculation allows 500 ppm sulfur NR and LM diesel fuel to increase proportionately, satisfying both needs. 500 ppm sulfur NR and LM diesel fuel compliance will be required on an annual basis, for terminal facilities as well as other entities. Compliance with the volume balance requirement is determined by comparing volumes received and delivered during that compliance period.

Facilities must maintain records regarding each transfer of 500 ppm sulfur NR and LM diesel fuel that they receive and discharge from June 1, 2010 through May 31, 2012 on a batch-by-batch basis. These records must include the EPA registration number of the source or recipient facility, and the volume of each fuel transfer. However, for transfers of marked 500 ppm sulfur LM diesel fuel, the recipient or source facility need not be specifically identified. In such cases, records must be kept regarding the total volume of marked 500 ppm sulfur LM diesel fuel that is received, discharged, and in inventory during each compliance period. For transfers of dyed 500 ppm sulfur NR diesel fuel from a truck loading rack, the specific recipients also do not need to be identified. In such cases, records must be kept regarding the total volume of 500 ppm sulfur NR diesel fuel that is received, discharged, and in inventory during each compliance period.

EPA plans to work closely with members of the diesel fuel refining and distribution industry, to provide clear and comprehensive guidance on what is expected of the various parties under the designate and track and volume balance provisions adopted in this rule. EPA invites suggestions from these parties on the most useful ways to provide such guidance.

d. Reporting Requirements

i. Compliance and Reporting Periods

We believe that any regulatory program should promote compliance and deter non-compliance. Today's program includes compliance and reporting provisions to deter noncompliance and to detect and correct instances of noncompliance in a timely fashion. Under today's program entities must submit to the Agency compliance reports containing information on the diesel fuel volumes they handle, separately by fuel designation category. Compliance with these volume designation and tracking requirements will be determined on an annual basis for refiners and pipelines and a quarterly basis for terminals during the first step of today's program. Compliance will be determined on an annual basis for everyone after 2010. To demonstrate compliance, refiners, pipelines, and terminals will be required to submit reports on a quarterly basis during the first step of today's program and then on an annual basis every year thereafter.

We are requiring the submission of volume reports on a quarterly basis during the first step of today's program for several reasons. First, and most importantly, today's program allows entities to change the designations of 500 ppm sulfur diesel fuel from NRLM diesel fuel to highway diesel fuel and heating oil to NRLM diesel fuel on a daily basis (provided that they later redesignate the same volume of 500 ppm diesel fuel from highway diesel fuel to NRLM diesel fuel and the same volume of NRLM diesel fuel to heating oil). Second, quarterly reporting coupled with quarterly compliance by terminals will constrain the magnitude of any noncompliance. Finally, during the start up of the designate and track system, there may also be a greater potential for errors in the transmission of records between custodians of designated fuels, in the calculations related to compliance with the volume account balance requirements, and in the materials provided in reports.

Today's program establishes quarterly compliance periods which are based on standard industry practices. Specifically, the quarterly compliance periods finalized in today's rule are as follows:

- 1st quarter: July 1–September 30;
- 2nd quarter: October 1–December 31;
- 3rd quarter: January 1–March 31;
- 4th quarter: April 1–June 30.

Where the start and end dates of the program do not line up with these dates, the quarters are lengthened or shortened accordingly (*e.g.*, June 1, 2007–September 30, 2007, and April 1, 2010–May 31, 2010). Quarterly reports are due two months following the end of the quarterly compliance period (*i.e.*, December 1, March 1, June 1, and September 1). Annual compliance periods begin on July 1 and end June 30 of the following year. Again, certain annual compliance periods were lengthened or shortened to match the significant dates of the program (*e.g.*, June 1, 2007–June 30, 2008). Annual reports are due by August 31 following the annual compliance period. For the sake of simplifying compliance and record keeping, the compliance periods for the highway final rule have been adjusted to match these.

Reports must be submitted electronically, or in a form which facilitates direct entry into an electronic database. Without reliance on an electronic database and reporting system to cross check and verify reported information, the designate and track provisions would become so cumbersome as to be virtually unenforceable by EPA staff given projected resource availability.

ii. Reporting Requirements During the First Step of Today's Program

During the first step of today's program, from June 1, 2007 through May 31, 2010, entities must report to EPA for each of their facilities regarding the total volume of each of the designated fuels that they receive from, or discharge to, another entity's facility in the fuel distribution system. If a facility is a refiner as well as a distributor (*e.g.*, a blender of biodiesel or blendstocks from unfinished diesel fuel or heating oil or otherwise both accepts previously designated fuel and also produces fuel), it must also report both volumes produced and released to other entities in its capacity as refiner and also report the volumes received and released for each designation like any other terminal or pipeline.

For example, an entity that operates a pipeline may have multiple points where it discharges fuel, and at each of these points it may supply multiple terminals. The pipeline operator must report on the receipt of designated fuel from each party that transfers fuel to it, and on the designated fuel transferred by the pipeline at each discharge point which specifies the fuel transferred, separately for each of its terminal customers. Entities must report for each of their facilities the total volumes of the designated fuels that were either dyed red, marked, or on which taxes were assessed tax while in their custody. Reports regarding these volumes do not need to include details on the recipients of the fuel (but product transfer documents must be kept to facilitate EPA's ability to compare the outgoing transfers and to fuel received).

Entities that handle only dyed NRLM diesel fuel, dyed and marked 500 ppm sulfur LM diesel fuel (2010–2012) and heating oil, or highway diesel fuel on which taxes have been assessed do not need to report to EPA. Information from such entities is not needed for compliance purposes, because there is no chance of violating the prohibitions against the shifting of fuel from one pool to another contained in today's rule without also violating either the requirement that highway diesel fuel contain no red dye, or the requirement that NRLM diesel fuel contain no heating oil marker. Furthermore, consistent with the highway rule, there are no periodic reporting requirements regarding the demonstration of compliance with the highway program's anti-downgrading requirements in today's rule. Maintenance of records should be sufficient for EPA to adequately monitor compliance with these requirements, as insufficient 15 ppm sulfur diesel fuel availability in an area should highlight potential anti-downgrading violations.

Quarterly reports from facilities downstream of the refinery and importer must also include data on the total volume of the designated fuels received, discharged, and in inventory during the quarterly reporting period. Using these data, the reporting party must demonstrate compliance with the volume account balance requirements regarding highway diesel fuel and high sulfur NRLM.

iii. Reporting Requirements During the Second Step of Today's Program

We believe that we may safely dispense with quarterly reporting and compliance evaluations starting June 1, 2010 and instead rely on annual reports. During the second step of today's rule, the designate and track requirements will be focused on preventing the use of heating oil in NRLM equipment, and during 2010–2012 preventing the use of 500 ppm sulfur LM diesel fuel in nonroad equipment. By 2010, all reporting parties in the system will have had experience in complying with the program's designate and track provisions. In addition, the Agency will have had ample experience in administering the system. Consequently, we expect that there will be few errors or omissions in reports and that EPA will have determined how best to detect and remedy instances of noncompliance. We believe an annual reporting period is therefore sufficient and appropriate.

Beginning June 1, 2010, entities that produce, import, or take custody of 500 ppm sulfur NRLM diesel fuel, marked heating oil, or unmarked heating oil outside of the Northeast/Mid-Atlantic area and Alaska, must submit an annual report to EPA that provides summary information regarding the transfer of these fuels.[126] Entities must report for each of their facilities the total volume of each of these fuels that they received from, or discharge to, another entity's facility in the fuel distribution system during each annual compliance period. For batches of heating oil that are delivered marked, the reports do not need to indicate the entities to which the batches were delivered—only the total volume of marked heating oil delivered during each compliance period must be reported. If an entity only receives marked heating oil (*i.e.*, it does not receive any unmarked heating oil), it does not need to report at all. If a facility received marked heating oil in addition to unmarked heating oil, it must report the volume of marked heating oil separately and indicate the facility from which the marked heating oil was received.

Beginning June 1, 2010 to June 1, 2012, entities that produce, import, or take custody of 500 ppm sulfur NR and LM diesel fuel outside of the Northeast/Mid-Atlantic area and Alaska, must submit an annual report to EPA that provides summary information regarding the transfer of these fuels.[127] Entities must report for each of their facilities the total volume of each of these fuels that they received from, or discharge to, another entity's facility in the fuel distribution system during each annual compliance period. For batches of 500 ppm sulfur LM diesel fuel that are delivered marked, the reports do not need to indicate the entities to which the batches were delivered—only the total volume of marked 500 ppm sulfur LM diesel fuel delivered during each compliance period must be reported. If an entity only receives marked 500 ppm sulfur LM diesel fuel (*i.e.*, it does not receive any unmarked 500 ppm sulfur LM diesel fuel), it does not need to report at all. If a facility received marked in addition to unmarked 500 ppm sulfur LM diesel fuel, it must report the volume of marked 500 ppm sulfur LM diesel fuel separately and indicate the facility from which the marked 500 ppm sulfur LM diesel fuel was received.

E. How Are State Diesel Fuel Programs Affected by the Sulfur Diesel Program?

Section 211(c)(4)(A) of the CAA prohibits states and political subdivisions of states from prescribing or attempting to enforce, for purposes of motor vehicle emission control, "any control or prohibition respecting any characteristic or component of a fuel or fuel additive in a motor vehicle or motor vehicle engine," if EPA has prescribed "a control or prohibition applicable to such characteristic or component of the fuel or fuel additive" under section 211(c)(1). This prohibition applies to all states except California, as explained in section 211(c)(4)(B). This express preemption provision in section 211(c)(4)(A) applies only to controls or prohibitions respecting any characteristics or components of fuels or fuel additives for motor vehicles or motor vehicle engines, that is, highway vehicles. It does not apply to controls or prohibitions respecting any characteristics or components of fuels or fuel additives for nonroad engines or nonroad vehicles.[128]

Section 211(c)(4)(A) specifically mentions only controls respecting characteristics or components of fuel or fuel additives in a "motor vehicle or motor vehicle engine," adopted "for purposes of motor vehicle emissions control," and the definitions of motor vehicle and nonroad engines and vehicles in CAA section 216 are mutually exclusive. This is in contrast to sections 211(a) and (b), which specifically mention application to fuels or fuel additives used in nonroad engines or nonroad vehicles, and with section 211(c)(1) which refers to fuel used in motor vehicles or engines or nonroad engines or vehicles.

Thus, today's action does not preempt state controls or prohibitions respecting characteristics or components of fuel or fuel additives used in nonroad, locomotive, or marine engines or

[126] 500 ppm sulfur NR diesel fuel, and starting June 1, 2012, 500 ppm sulfur NRLM diesel fuel, is not permitted in the Northeast/Mid-Atlantic area and only in the State of Alaska in limited circumstances.

[127] During this time period, 500 ppm sulfur NR diesel fuel is not permitted in the Northeast/Mid-Atlantic area and only in the State of Alaska in limited circumstances.

[128] *See* 66 FR 36543, July 12, 2001 (notice proposing approval of Houston SIP revisions). *See also* letter from Carl Edlund, Director, Multimedia Planning and Permitting Division, U.S. Environmental Protection Agency, Region VI, to Jeffrey Saitas, Executive Director, Texas Natural Resources Conservation Commission, dated September 25, 2000, providing comments on proposed revisions to the Texas State Implementation Plan for the control of ozone, specifically the Post 99 Rate of Progress Plan and Attainment Demonstration for the Houston/Galveston area. This letter noted that preemption under section 211(c)(4) of the CAA did not apply to controls on nonroad diesel fuel.

nonroad, locomotive, or marine vehicles under the provisions of section 211(c)(4)(A). At the same time, a state control that regulates both highway fuel and nonroad fuel is preempted to the extent that the state control respects a characteristic or component of highway fuel regulated by EPA under section 211(c)(1).

A court may consider whether a state control for fuels or fuel additives used in nonroad engines or nonroad vehicles is implicitly preempted under the supremacy clause of the U.S. constitution. Courts have determined that a state law is preempted by federal law where the state requirement actually conflicts with federal law by preventing compliance with the federal requirement, or by standing as an obstacle to accomplishment of congressional objectives. A court could thus consider whether a given state standard for sulfur in nonroad, locomotive or marine diesel fuel is preempted if it places such significant cost and investment burdens on refiners that refiners cannot meet both state and federal requirements in time, or if the state control would otherwise meet the criteria for conflict preemption.

F. Technological Feasibility of the 500 and 15 ppm Sulfur Diesel Fuel Program

This section summarizes our assessment of the feasibility of refining and distributing 500 ppm NRLM diesel fuel starting in 2007 and 15 ppm nonroad diesel fuel in 2010 and locomotive and marine diesel fuel in 2012. Based on this evaluation, we believe it is technologically feasible for refiners and distributors to meet both sulfur standards in the lead time provided with the desulfurization technology available. We begin this section by describing the nonroad, locomotive and marine diesel fuel market and how these fuels differ from current highway diesel fuel. We discuss desulfurization technologies, both conventional and advanced, which are available for complying with the 500 ppm and 15 ppm NRLM standards. We then present what mix of technologies we believe will be used. Next we provide our analysis of the lead time for complying with either standard. Finally, we analyze the feasibility of distributing low sulfur NRLM diesel fuel. We refer the reader to the Final RIA for more details regarding these assessments.

1. What Is the Nonroad, Locomotive and Marine Diesel Fuel Market Today?

Nonroad, locomotive and marine (NRLM) engines almost exclusively use No. 2 distillate fuel. No. 2 distillate fuel is a class of fuel defined by its boiling range. It boils at a higher average temperature than gasoline, No. 1 distillate, jet fuel and kerosene, and at a lower average temperature than residual fuel (or bunker fuel). ASTM defines three No. 2 distillate fuels: (1) Low sulfur No. 2 diesel fuel (No. 2–D); (2) high sulfur No. 2–D; and (3) No. 2 fuel oil.[129] Low sulfur No. 2–D fuel must contain 500 ppm sulfur or less, have a minimum cetane number of 40, and have a minimum cetane index limit of 40 (or a maximum aromatic content of 35 volume percent) (*i.e.*, meet the EPA standard for highway diesel fuel).[130] Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,[131] and currently averages 3000 ppm nationwide. The ASTM specification for high sulfur No. 2–D fuel also includes a minimum cetane number of 40. Practically, since most No. 2 fuel oil meets this minimum cetane number specification, pipelines which ship fuel fungibly need only carry one high sulfur No. 2 distillate fuel which meets both sets of specifications. Currently, nonroad, locomotive and marine engines can be and are fueled with both low and high sulfur No. 2–D fuels. If No. 1 distillate is blended into highway diesel fuel, as is sometimes done to prevent gelling in the winter, the final blend must meet the 500 ppm EPA cap.

No. 1 distillate (*e.g.*, jet fuel and kerosene) meets lower boiling point and viscosity specifications requirements than No. 2 distillate. No. 1 distillate, or any of these other similar boiling distillates, added to No. 2 NRLM distillate becomes NRLM diesel fuel and thus, must meet the applicable specifications for No. 2 distillate.

For the purpose of this rule, we split the No. 2 distillate market into three pieces, according to the sulfur standard which each must meet: (1) Highway diesel fuel, (2) NRLM diesel fuel, and heating oil, which is used in both furnaces and boilers, as well as in stationary diesel engines to generate power.

In the NPRM, EPA estimated current production and demand for NRLM fuel from studies conducted by the U.S. Energy Information Administration (EIA). We projected growth in nonroad fuel demand using EPA's NONROAD emission model. We based the growth in locomotive and marine fuel demand from analyses supporting EPA's locomotive and marine engine rulemaking. These future levels of NRLM fuel demand differed from those implicit in our projection of the emission reductions associated with the rule, which were based primarily on EPA's NONROAD emission model. We pointed out this inconsistency in the rule and indicated that we would resolve this inconsistency for the final rule.

In their comments on the NPRM, the American Petroleum Institute (API), the Engine Manufacturers Association (EMA) and others highlighted this inconsistency and suggested that EPA resolve it by basing its projection of future NRLM fuel demand using information developed by EIA and not from the NONROAD emission model. API pointed to a lower estimate of nonroad fuel demand developed in a contracted study performed by Baker and O'Brien. A detailed analysis of these comments and additional technical analyses of distillate fuel demand are described in Section 4.6.3.1 of the Summary and Analysis document to this rule. In summary, we decided to continue using the NONROAD emission model to project the emission benefits of this rule. To eliminate the inconsistency in the NPRM, we also use the NONROAD model to determine demand for nonroad fuel and project the economic impacts of this final rule. However, the analyses presented in Section 4.6.3.1 of the Summary and Analysis document to this rule identified uncertainties in the current and future level of nonroad fuel demand. To insure that these uncertainties did not affect the outcome of this rulemaking process, we evaluate the emissions, costs and cost effectiveness of the standards contained in this rule using an alternative estimate of nonroad fuel demand derived from EIA information. This alternative analysis is presented in Appendix 8A of the Final RIA. In addition to use of the NONROAD model to project nonroad fuel demand, we also updated our projections of the production of and demand for highway fuel and heating oil using more recent versions of the same EIA reports used in the NPRM analysis.

In 2001, nationwide outside of California, nonroad diesel fuel comprised about 18 percent of all No. 2 distillate fuel, while locomotive and marine diesel fuel comprised about eight percent of all No. 2 distillate fuel. Diesel fuel consumed by highway vehicles/engines comprised about 56 percent of all No. 2 distillate fuel.

[129] "Standard Specification for Diesel Fuel Oils," ASTM D 975–98b and "Standard Specifications for Fuel Oils," ASTM D 396–98.

[130] These ASTM requirements were formed after and are consistent with the EPA regulations for highway diesel fuel.

[131] Some states, particularly those in the Northeast, limit the sulfur content of No. 2 fuel oil to 2000–3000 ppm.

Heating oil comprised about 19 percent of No. 2 distillate. Because of limitations in the fuel distribution system and other factors, about 18 percent of all non-highway distillate met the 500 ppm highway diesel fuel cap. Thus, about 64 percent of No. 2 distillate pool met the 500 ppm sulfur cap, not just the 56 percent used in highway vehicles. We project that this spillover of highway fuel to the NRLM diesel fuel market will continue under the highway diesel fuel program. Thus, today's rule will only materially affect about 19 percent of today's distillate market. The remaining 17 percent of No. 2 distillate which is high sulfur heating oil is estimated to remain at higher sulfur levels.

This rule will also affect any No. 1 distillate which is blended into wintertime NRLM fuel. Because gelling can also be prevented through the use of pour point additives, the current and future level of this of No. 1 distillate blending is uncertain. However, the feasibility of desulfurizing and distributing this No. 1 distillate will also be addressed below.

2. What Technology Will Refiners Use To Meet the 500 ppm Sulfur Cap?

Refiners currently hydrotreat most or all of their distillate blendstocks using what is commonly referred to as "conventional" hydrotreating technology to meet the 500 ppm sulfur and cetane limits applicable to highway diesel fuel. This conventional technology has been available and in use for many years. U.S. refiners have nearly ten years of experience with this technology in producing highway diesel fuel. The distillate blendstocks comprising NRLM fuel do not differ substantially from those comprising highway diesel fuel. Thus, the technology to produce 500 ppm sulfur NRLM diesel fuel has clearly been demonstrated and optimized over the last decade. Additionally, this technology continues to evolve primarily through the development of more active catalysts and motivated by the 15 ppm cap applicable to most highway diesel fuel starting in 2006.

Several advanced desulfurization technologies are being developed and are discussed in more detail in the next section. However, the fact that none of these technologies have been demonstrated commercially for a typical catalyst life (*i.e.*, two years) makes it unlikely that they would be selected by many refiners for use in mid-2007. Also, these advanced technologies promise the greatest cost savings in achieving 15 ppm levels, rather than 500 ppm. These advanced technologies can also be combined with a conventional hydrotreater to meet the 15 ppm standard in 2010 and 2012. EPA therefore projects that the 500 ppm sulfur cap NRLM standard will be met using conventional hydrotreating technology. We made this same projection in the NPRM and no comments to the contrary were received.

In some cases, refiners will also need to install or expand several ancillary processes related to sulfur removal (*e.g.*, hydrogen production and purification, sulfur processing, and sour water treatment). These technologies are all commercially demonstrated, as nearly all refineries already have such units.

3. Is the Leadtime Sufficient To Meet the 2007 500 ppm NRLM Sulfur Standard?

After the highway diesel fuel program is implemented, we project that 92 refineries in U.S. will be producing high sulfur distillate fuel. We project that 36 of these refineries will likely produce 500 ppm sulfur NRLM diesel fuel in 2007. Of those 36, 30 will have to build new hydrotreaters while the other 6 are expected to use existing hydrotreaters to produce 500 ppm NRLM diesel fuel.[132] The remaining 56 refineries are projected to continue to produce high sulfur distillate fuel, with 26 of the 56 refineries producing heating oil. The other 30 refineries are owned by small refiners and will likely produce high sulfur NRLM diesel fuel. The 56 refineries continuing to produce high sulfur distillate will not have to add or modify any equipment to continue producing this fuel.

This rule will provide refiners and importers 37 months before they will have to begin producing 500 ppm NRLM diesel fuel on June 1, 2007. Our lead time analysis projects that 27–39 months are typically needed to design and construct a diesel fuel hydrotreater.[133] As discussed below, we believe that 37 months will be sufficient for all refiners of NRLM fuel.

Easing the task is the fact that we project that essentially all refiners will use conventional hydrotreating to comply with the 500 ppm sulfur NRLM diesel fuel cap. This technology has been used extensively for more than 10 years and its capabilities to process a wide range of diesel fuel blendstocks are well understood. Thus, the time necessary to apply this technology for a specific refiner's situation should be relatively short.

Twenty-six out of the 36 refineries projected to produce 500 ppm NRLM diesel fuel in 2007 have indicated that they will produce highway diesel fuel in their highway diesel fuel pre-compliance reports, *see* RIA section 7.2.1.3.4.1, Table 7.2.1–38 and following discussion for description of these refineries. Thus, roughly 70% of the refiners likely to produce 500 ppm sulfur NRLM diesel fuel in 2007 are already well into their planning for meeting the 15 ppm highway diesel fuel standard, effective June 1, 2006. It is likely that these refiners have already chemically characterized their high sulfur diesel fuel blendstocks, as well as their highway diesel fuel, in assessing how to meet produce 15 ppm fuel. They will also have already assessed the various technologies for producing 15 ppm diesel fuel. This provides an extensive base of information on how to design a hydrotreater to produce 500 ppm NRLM fuel, as well as how to revamp this hydrotreater to produce 15 ppm NRLM diesel fuel in 2010 and 2012. Those refiners only producing high sulfur distillate fuel today will be able to take advantage of the significant experience that technology vendors have obtained in assisting refiners of highway diesel fuel meet the 15 ppm cap in 2006.

We also expect that roughly 20 percent of the 101 refineries in the U.S. and its territories will build a new hydrotreater to produce 15 ppm highway fuel. Those which also produce high sulfur distillate will be able to produce 500 ppm NRLM fuel with their existing highway hydrotreater. In 2007, we conservatively assumed that 20% of the 500 ppm NRLM production from refineries that produce highway and high sulfur distillate could be produced with these existing treaters at no capital costs (existing highway treater capacity available for 500 ppm NRLM production would be higher if based on highway treater capacity). Thus, in 2007 we project that four refineries will be able to use their recently idled highway treater due to building a new highway treater unit for 2006. Furthermore, the highway diesel program pre-compliance reports indicate that another 7 refineries currently producing 500 ppm highway fuel will likely leave the highway fuel market in 2006. We project that 2 of these would use their existing treater to produce 500 ppm NRLM with no investment costs. Another three of these 101 refineries produce relatively small volumes of high sulfur distillate compared to highway diesel fuel today. We project that they will be able to

[132] These refiners have said that they will leave the highway market in 2006 in their pre-compliance reports for complying with the Highway Diesel Rule, thus freeing up their existing hydrotreaters to produce 500 ppm NRLM diesel fuel.

[133] "Highway Diesel Progress Review," USEPA, EPA420–R–02–016, June 2002. The leadtime analysis in the RIA can be found in section 5.3.

produce 500 ppm sulfur NRLM fuel from their high sulfur distillate with only minor modification to their existing highway diesel fuel hydrotreater.

Refiners not planning on producing 100 percent highway fuel in 2006 will also need some time to assess which distillate market in which to participate starting in 2007, NRLM or heating oil. While this is a decision which requires some amount of time for analysis, refiners also needed to assess what market they would participate in for the 1993 500 ppm highway diesel fuel sulfur cap. In all, we project that the task of producing 500 ppm sulfur NRLM fuel in 2007 will be less difficult than the task refiners faced with the implementation of the 500 ppm highway diesel fuel cap in 1993. Refiners had just over three years of lead time for complying with the 1993 500 ppm highway diesel fuel cap, as is the case here, and this proved sufficient.

No explicit comments were made by refiners on the lead time needed for complying with the proposed NRLM 500 ppm sulfur standard. However, their comments supported the two step approach, preferring it over a one step, 15 ppm NRLM cap starting in 2008.

4. What Technology Will Refiners Use To Meet the 15 ppm Sulfur Cap?

In the highway diesel rule, we projected that refiners producing 15 ppm fuel in 2006 would utilize extensions of conventional hydrotreating technology. We also projected that refiners first producing 15 ppm fuel in 2010 would use a mix of extensions of conventional and advanced technologies. Based on the refiners' highway pre-compliance reports, it appears that 95% of highway fuel could meet the 15 ppm cap in 2006. We expect that virtually all of this 15 ppm fuel will be produced with conventional hydrotreating. Thus, it appears that conventional hydrotreating will be used to produce the vast majority of 15 ppm highway diesel fuel.

In the nonroad NPRM, we projected that refiners would use advanced desulfurization technologies to produce 80 percent of 15 ppm nonroad diesel fuel in 2010, with the balance using conventional hydrotreating. At the time of the NPRM, all of the advanced technologies appeared to be progressing rapidly. Since the proposal, we have learned that a couple of these technologies, Unipure and S-Zorb, are not going to be commercially demonstrated as soon as expected. However, one refiner is already using Process Dynamics' IsoTherming technology to commercially produce 15 ppm diesel fuel. Thus, we continue to believe that advanced technologies will be used to produce a large percentage of 15 ppm NRLM fuel. However, the number of advanced technologies used may be smaller. Because of the more limited choices, we project that the penetration of advanced technologies will be only 60 percent. The remainder of this section discusses the production of 15 ppm diesel fuel using conventional and advanced technologies.

One approach to produce 15 ppm NRLM fuel would be to revamp the conventional hydrotreater built to produce 500 ppm NRLM fuel in 2007. Knowing that the 500 ppm NRLM cap will only be in effect for three years for nonroad refiners and five years for locomotive and marine refiners (four years for small refiners), we expect that refiners will design their 500 ppm hydrotreater to allow the production of 15 ppm fuel through the addition of reactor volume or a second hydrotreating stage. Refiners might also shift to a more active catalyst in the existing reactor, as the life of that catalyst might be nearing its end. Equipment to further purify its hydrogen supply could also be added. Producing 15 ppm NRLM fuel via these steps will be feasible as they are essentially the same steps refiners will be using in 2006 to produce 15 ppm highway diesel fuel.

EPA recently reviewed the progress being made by refining technology vendors and refiners in meeting the 2006 highway diesel sulfur cap.[134] All evidence available confirms EPA's projection that conventional hydrotreating will be capable of producing diesel fuel containing less than 10 ppm sulfur. Furthermore, as part of the highway program's reporting requirements, refiners are required to report their progress in complying with the 15 ppm highway diesel fuel standard. In those reports they indicated that they primarily will be applying extensions of conventional hydrotreating. NRLM fuel refiners will have the added advantage of being able to design their 500 ppm hydrotreater with the production of 15 ppm fuel in mind. Additionally, refiners producing 15 ppm NRLM fuel will be able to take advantage of the experience gained from those producing 15 ppm highway fuel.

As mentioned above, several advanced technologies are presently being developed to produce 15 ppm diesel fuel at lower cost. One of these advanced technologies, Process Dynamics IsoTherming, improves the contact between hydrogen, diesel fuel and the desulfurization catalyst. The IsoTherming process dissolves the hydrogen in the liquid fuel phase prior to passing the liquid over the catalyst, eliminating the need for a two-phase (gas and liquid) reactor. The liquid, plug flow reactor design also avoids the poor liquid distribution over the catalyst bed often present in a two-phase reactor design. Process Dynamics projects that their IsoTherming process could reduce the hydrotreater volume required to achieve sub-15 ppm sulfur levels by roughly a factor of two.

Process Dynamics has already built a commercial-sized demonstration unit (5000 barrels per day) at a refinery in New Mexico. They have been operating the unit since September 2002, and demonstrating the capability to meet a 15 ppm cap since the spring of 2003. Thus, refiners will have 4–5 years of operating data on this process before they would have to select a technology to produce 15 ppm nonroad diesel fuel in 2010, and 6–7 years before producing 15 ppm locomotive and marine diesel fuel in 2012. This should be more than sufficient for essentially all refiners to consider this process for 2010 or 2012. Based on information received from Process Dynamics, we estimate that this technology could reduce the cost of meeting the 15 ppm cap for many refiners by about 30 percent. This savings arises from a smaller reactor, less catalyst and avoiding the need for a recycle gas compressor and reactor distributor. Refineries facing poorer economies of scale, such as small refineries, would particularly benefit from this desulfurization process.

A second process being developed to produce 15 ppm diesel fuel is the Unipure oxidation process. This process oxidizes the sulfur in distillate molecules, facilitating its removal. Unipure Corporation installed a small (50 barrels per day), continuous flow demonstration unit at Valero's Krotz Spring refinery in the spring of 2003. It appears that this technology could reduce the cost of producing 15 ppm diesel fuel for some refiners compared to conventional hydrotreating. However, the small size of the demonstration unit may make the risk associated with a new technology too large. Thus, we believe that this technology needs be demonstrated further before most refiners will seriously considered it for commercial application. This technology, however, may be ideal for use at transmix processing plants or large terminals to reprocess 15 ppm diesel fuel which have become contaminated during shipment. We

[134] "Highway Diesel Progress Review," USEPA, EPA420–R–02–016, June 2002.

discuss this distillate downgrade in greater detail in Section VI.A.2 of this preamble. This oxidation process avoids the need for high pressure hydrogen, which is usually not economically available at these smaller facilities.

Finally, Conoco-Phillips has adapted their S–Zorb adsorption technology which was originally designed for gasoline desulfurization, for diesel fuel desulfurization. At the time of the NPRM, Conoco-Phillips had signed 23 licensing agreements with refiners in North America regarding the use of S-Zorb to comply with the Tier 2 gasoline sulfur standards. Furthermore, Conoco-Phillips had plans for the quick installation of an S-Zorb unit to demonstrate the production of 15 ppm diesel fuel. However, we have since learned that Conoco-Phillips has dropped its plans to build a commercial demonstration unit for desulfurizing diesel fuel. Without a commercial unit operating in the 2006 time frame, we do not believe that many refiners will seriously consider S-Zorb to produce 15 ppm NRLM diesel fuel in 2010 and 2012.

Due to the fact that the Process Dynamics IsoTherming process is already operating commercially and operational data indicate a 30 percent reduction in the cost of producing 15 ppm fuel relative to conventional hydrotreating, we project that 60 percent of the new volume of 15 ppm NRLM diesel fuel will be produced using this technology. We project that the remaining 40 percent of 15 ppm NRLM diesel fuel will use extensions of conventional hydrotreating. We assume this 60/40 mix of Isotherming and extensions of conventional hydrotreating, respectively, for 2010, 2012 and even for 2014 when the small refiners exemptions expire.

API commented that the advanced desulfurization technologies have not been commercially demonstrated and thus should not be used as the basis for estimating the cost of desulfurizing NRLM diesel fuel to 15 ppm. While this is true for the Unipure oxidation and Conoco-Phillip's S-Zorb processes, the Process Dynamics IsoTherming process has been commercially demonstrated. It is therefore appropriate for use as a partial basis for the refining costs associated with today's final rule. To indicate the effect that this projection for the use of IsoTherming has on the rule's cost, in Section 7.2.2 of the Final RIA, we estimate the cost of producing 15 ppm NRLM fuel with only the use of conventional hydrotreating technology.

5. Is the Leadtime Sufficient To Meet the 2010 and 2012 15 ppm NRLM Sulfur Cap?

We project that 32 refineries will produce 15 ppm nonroad diesel fuel in 2010, with two of these being owned by small refiners. In 2012, we project that 15 refineries will produce 15 ppm locomotive and marine diesel fuel. We project that an additional 15 refineries will produce 500 ppm nonroad diesel fuel in 2010 under the small refiner provisions included in the today's final rule. Then in 2014, we project that the 15 refineries exempted under the small refiner provisions will begin producing 15 ppm NRLM diesel fuel in 2014.

The timing of this rule provides refiners and importers with more than six years before they will have to produce 15 ppm nonroad diesel fuel, and two years more for producing 15 ppm locomotive and marine diesel fuel. Our leadtime analysis, which is presented in Section 5.4.2 of the Final RIA, projects that 30–39 months are typically needed to design and construct a diesel fuel hydrotreater, perhaps less if it is a Process Dynamics unit. Thus, refiners will have about three years before they would have to begin detailed design and construction for 2010, and five years before 2012. This will allow sufficient time to consult with vendors, test their diesel fuel in pilot plants to assess the difficulty of its desulfurization via a variety of technologies, and to select its technology for 2010 and 2012. In addition, these refiners will also have the chance to observe the performance of the hydrotreaters being used to produce 15 ppm highway diesel fuel for at least one year for those complying in 2010, and two years more for those complying in 2012. While not a full catalyst cycle, any unusual degradation in catalyst performance should be apparent within the first year. Based on the pre-compliance reports, some refineries in the U.S. will be producing 15 ppm sulfur highway diesel fuel earlier than 2006. Some refineries are expected to produce complying fuel earlier than the compliance date in Europe as well. The refineries which are complying early will accrue experience earlier and longer providing refiners a better sense of the reliability of producing 15 ppm diesel fuel. Thus, we project that the 2010 and 2012 start dates will allow refiners to be quite certain that the designs they select in mid-2007 will perform adequately in 2010 and 2012.

In addition, refiners will have three to four years or more to observe the performance of the Process Dynamics IsoTherming process before having to make their technology selections for 2010 and 2012 . This should be more than adequate to fully access the costs and capabilities of this technology for all but the most cautious refiners.

Considering the amount of leadtime available and the desulfurization technologies which will be available and proven for complying with a 15 ppm sulfur standard, we do not expect that the leadtime for complying with the 15 ppm NRLM cap standard in 2010 and 2012 will be an issue for refiners.

6. Feasibility of Distributing 500 and 15 ppm NRLM Fuel

There are two considerations with respect to the feasibility of distributing non-highway diesel fuels meeting the sulfur standards in today's rule. The first pertains to whether sulfur contamination can be adequately managed throughout the distribution system so that fuel delivered to the end-user does not exceed the specified maximum sulfur concentration. The second pertains to the physical limitations of the system to accommodate any additional segregation of product grades.

a. Limiting Sulfur Contamination

With respect to limiting sulfur contamination during distribution, the physical hardware and distribution practices for non-highway diesel fuel do not differ significantly from those for highway diesel fuel. Therefore, we do not anticipate any new issues with respect to limiting sulfur contamination during the distribution of non-highway fuel that would not have already been accounted for in distributing highway diesel fuel. Highway diesel fuel has been required to meet a 500 ppm sulfur standard since 1993. Thus, we expect that limiting contamination during the distribution of 500 ppm non-highway diesel engine fuel can be readily accomplished by the industry. This applies to locomotive and marine diesel fuel as well as nonroad diesel fuel.

In the highway diesel rule, EPA acknowledged that meeting a 15 ppm sulfur specification would pose a substantial new challenge to the distribution system. Refiners, pipelines, and terminals would have to pay careful attention to and eliminate any potential sources of contamination in the system (*e.g.*, tank bottoms, deal legs in pipelines, leaking valves, interface cuts, etc.). In addition, bulk plant operators and delivery truck operators would have to carefully observe recommended industry practices to limit contamination, including practices as simple as cleaning out transfer hoses, proper sequencing of fuel deliveries, and parking on a level surface when draining the storage tank. Due to the need to prepare for compliance with the highway diesel program, we anticipate that issues related to limiting sulfur contamination during the distribution of 15 ppm NRLM diesel fuel will be resolved well in advance of the 2010 and 2012 implementation dates . We are not aware of any additional issues that might arise unique to NRLM diesel fuel. If anything we anticipate limiting contamination will become easier as batch sizes are allowed to increase and potential sources of contamination decrease as more and more of the diesel pool turns over to 500 and 15 ppm sulfur. Industry representatives acknowledge that the task can be accomplished. However, they are still in the process of identifying all of the measures that will need to be taken.

b. Potential Need for Additional Product Segregation

As discussed in section IV.D, we have designed the NRLM diesel fuel program to minimize the need for additional product segregation and the feasibility and cost issues associated with it. This final rule allows for the fungible distribution of 500 ppm highway and 500 ppm sulfur NRLM diesel fuel in 2007, and 15 ppm highway and 15 ppm NR diesel fuel in 2010 and 15 ppm NRLM diesel fuel in 2012, up until the point where NRLM, LM, or nonroad fuel must be dyed for IRS excise tax purposes. We proposed that heating oil would be required to be segregated throughout the distribution system by the use of a marker added at the refiners from 2007 through 2010. We received comments that addition of the marker at the refinery would cause significant concerns regarding potential marker contamination in the jet fuel. In responding to these and other comments, we have chosen to adopt a designate and track system of ensuring refiner compliance with desulfurization requirements (*see* IV.D.). This allows the point of marker addition to be moved downstream to the terminal where such contamination concerns are minimal. As a result heating oil and high-sulfur NRLM will also be fungible in the distribution system up to the point where the fuel marker must be added at the terminal.[135]

The design of today's fuel program eliminates any potential feasibility issues associated with the need for product segregation. This is not to say that additional steps will not have to be taken. However, this program will result in only a limited number of entities in the distribution system choosing to add new tankage due to new product segregation. Bulk plants in areas of the country where heating oil is expected to remain in the market will have to decide whether to add tankage to distribute both heating oil and 500 ppm sulfur NRLM fuel. Terminal operators commented that the proposed presence of a fuel marker in heating oil would make it impossible for them to blend 500 ppm sulfur diesel from 15 ppm sulfur and high sulfur fuels. They related that this ability would be important to certain terminal operators who would not have the storage facilities available for three grades of diesel fuel, but would still not wish to forgo selling 500 ppm diesel fuel.[136] Today's rule allows the required marker to be added to heating oil before it leaves the terminal (see section IV.D of this preamble). Therefore, terminals will be able to blend 500 ppm diesel from 15 ppm and high sulfur diesel fuels, provided they fulfill all of the responsibilities associated with acting as a fuel refiner (see section V of this preamble).[137] However, because this will be a relatively costly way of producing 500 ppm diesel fuel, we do not expect that the practice will be widespread. In all other cases we anticipate segments of the distribution system will choose to avoid any fuel segregation costs by limiting the range of sulfur grades they choose to carry, just as they do today. Regardless, however, the costs and impacts of these choices are small. A more detailed explanation of this assessment can be found in chapter 7 of the RIA.

A limited volume of 500 ppm sulfur diesel fuel is projected to be produced downstream due to interface mixing in the distribution system (*see* section IV.A).[138] Fuel from these sources is currently sold into the NRLM and heating oil markets. The implementation of the 15 ppm sulfur standard for NR diesel fuel in 2010 and for LM diesel fuel in 2012 raises the concern that the heating oil market might be insufficient to absorb all such downstream 500 ppm sulfur diesel fuel in areas outside of the Northeast (where most heating oil is used). If the market for this fuel was limited, it would have to be trucked back to a refinery to be desulfurized which could raise significant logistical and cost issues. Consequently, today's rule provides that 500 ppm sulfur diesel fuel produced due to interface mixing can continue to be used in nonroad equipment until 2014 (subject to specific sulfur requirements for new equipment), and in locomotive and marine engines indefinitely.[139] These provisions ensure that there will be a sufficient market for such 500 ppm sulfur diesel fuel.

G. What Are the Potential Impacts of the 15 ppm Sulfur Diesel Program on Lubricity and Other Fuel Properties?

1. What Is Lubricity and Why Might It Be a Concern?

Engine manufacturers and owner/operators depend on diesel fuel lubricity properties to lubricate and protect moving parts within fuel pumps and injection systems for reliable performance. Unit injector systems and in-line pumps, commonly used in diesel engines, are actuated by cams lubricated with crankcase oil, and have minimal sensitivity to fuel lubricity. However, rotary and distributor type pumps, commonly used in light and medium-duty diesel engines, are completely fuel lubricated, resulting in high sensitivity to fuel lubricity. The types of fuel pumps and injection systems used in nonroad diesel engines are the same as those used in highway diesel vehicles. Consequently, nonroad and highway diesel engines share the same need for adequate fuel lubricity to maintain fuel pump and injection system durability.

Diesel fuel lubricity concerns were first highlighted for private and commercial vehicles during the initial implementation of the federal 500 ppm sulfur highway diesel program and the state of California's diesel program. The Department of Defense (DoD) also has a longstanding concern regarding the lubricity of distillate fuels used in its equipment as evidenced by the implementation of its own fuel lubricity improver performance specification in 1989.[140] The diesel fuel requirements in the state of California differed from the

[135] The fuel marker requirements only apply outside of the Northeast/Mid-Atlantic area. Inside the Northeast/Mid-Atlantic area, high sulfur NRLM cannot be sold to end users. *See* section IV.D for a detailed discussion of the fuel marker provisions.

[136] 15 ppm diesel fuel and high sulfur heating oil will be the largest volume products at such terminals.

[137] The definition of a refiner includes persons who produce highway or NRLM diesel fuel by blending.

[138] This fuel will be produced by transmix processors and at terminals by segregating the pipeline interface between 15 ppm diesel fuel and jet fuel.

[139] While today?s rule does not contain an end date for the downstream distribution of 500 ppm sulfur locomotive and marine fuel, we will review the appropriateness of allowing this flexibility based on experience gained from implementation of the 15 ppm sulfur NRLM diesel fuel standard. We expect to conduct such an evaluation in 2011.

[140] DoD Performance Specification, Inhibitor, Corrosion/Lubricity Improver, Fuel Soluble, MIL–PRF–25017F, 10 November 1997, Superseding MIL–I–25017E, 15 June 1989.

federal requirements by substantially restricting the aromatic content of diesel fuel which requires more severe hydrotreating than reducing the sulfur content to meet a 500 ppm standard.[141] Consequently, concerns regarding diesel fuel lubricity have primarily been associated with California diesel fuel and some California refiners treat their diesel fuel with a lubricity additive as needed. Outside of California, hydrotreating to meet the current 500 ppm sulfur specification does not typically result in a substantial reduction of lubricity. Diesel fuels outside of California seldom require the use of a lubricity additive. Therefore, we anticipate only a marginal increase in the use of lubricity additives in NRLM diesel fuel meeting the 500 ppm sulfur standard for 2007.[142] Today's action requires diesel fuel used in nonroad, locomotive, and marine diesel engines to meet a 15 ppm sulfur standard in 2010 and 2012, respectively. Based on the following discussion, we believe that the increase in the use of lubricity additives in 15 ppm sulfur NRLM diesel fuel would be the same as that estimated for 15 ppm highway diesel fuel.

The state of California currently requires the same standards for diesel fuel used in nonroad equipment as in highway equipment. Outside of California, highway diesel fuel is often used in nonroad equipment when logistical constraints or market influences in the fuel distribution system limit the availability of high sulfur fuel. Thus, for nearly a decade nonroad equipment has been using federal 500 ppm sulfur diesel fuel and California diesel fuel, some of which may have been treated with lubricity additives. During this time, there has been no indication that the level of diesel lubricity needed for fuel used in nonroad engines differs substantially from the level needed for fuel used in highway diesel engines.

Blending small amounts of lubricity-enhancing additives increases the lubricity of poor-lubricity fuels to acceptable levels. These additives are available in today's market, are effective, and are in widespread use around the world. Among the available additives, biodiesel has been suggested as one potential means for increasing the lubricity of conventional diesel fuel. Indications are that low concentrations of biodiesel might be sufficient to raise the lubricity to acceptable levels. Biodiesel is a renewable fuel made from agricultural sources such as soybean oil, peanut oil and other vegetable oils as well as rendered and animal fats and recycled cooking oils. Biodiesel generally contains very low amounts of sulfur, which is an attractive characteristic for use in diesel engines using advanced aftertreatment systems. Additionally, biodiesel, by virtue of its lubricity properties, may be a good alternative to additives currently used to ensure adequate fuel lubricity. According to the U.S. Department of Agriculture, there is a current capacity to produce 100 million gallons annually. Thus, we believe that biodiesel is a feasible technology that could help support today's clean diesel fuel program.

Research remains to be performed to better understand which fuel components are most responsible for lubricity. Consequently, it is unclear whether and to what degree the sulfur standards for NRLM diesel fuel will impact fuel lubricity. Nevertheless, there is evidence that the typical process used to remove sulfur from diesel fuel "hydrotreating" can impact lubricity depending on the severity of the treatment process and characteristics of the crude. We expect that hydrotreating will be the predominant process used to reduce the sulfur content of NRLM diesel fuel to meet the 500 ppm sulfur standard during the first step of the program. Similarly, we project that both conventional hydrotreating and the Linde Isotherming process will be used to meet the 15 ppm sulfur standard for NRLM diesel fuel.

Based on our comparison of the blendstocks and processes used to manufacture non-highway diesel fuels, we believe that the potential decrease in the lubricity of these fuels from hydrotreating that might result from the sulfur standards should be approximately the same as that experienced in desulfurizing highway diesel fuel.[143] To provide a conservative, high cost estimate, we assumed that the potential impact on fuel lubricity from the use of the new desulfurization processes would be the same as that experienced when hydrotreating diesel fuel to meet a 15 ppm sulfur standard. Given that the requirements for fuel lubricity in highway and nonroad engines are the same, and the potential decrease in lubricity from desulfurization of NRLM diesel fuel would be no greater than that experienced in desulfurizing highway diesel fuel, we estimate that the potential need for lubricity additives in NRLM diesel fuel under today's action would be the same as that for highway diesel fuel meeting the same sulfur standard.

a. Farm and Mining Equipment

The types of fuel pumps and injection systems used in the nonroad diesel engines found in farm and mining equipment are similar to those used in highway diesel vehicles.[144] The hydrotreating process for generating 500 ppm diesel fuel will not adversely effect fuel injection equipment in farm and mining equipment based on the use of comparable injection systems in highway diesel vehicles. We believe that the use of lubricity additives in 15 ppm sulfur NRLM diesel fuel will be required and result in adequate protection of fuel injection equipment and is similar to that needed for 15 ppm sulfur highway diesel fuel.

b. Locomotives

One of the locomotive manufacturers expressed concern in its comments that low sulfur fuel might damage existing locomotives. However, the manufacturer provided no evidence to show that such damage would likely occur. Locomotives already use a significant amount of low sulfur fuel, especially in California, and we have not seen any evidence of sulfur-related problems. The railroads expressed a similar concern, but acknowledged that any potential problems would be manageable with sufficient lead time. At this time, we see no reason for any special concern related to locomotives using low sulfur fuel.

2. A Voluntary Approach on Lubricity

In the United States, there is no government or industry standard for diesel fuel lubricity. Therefore, specifications for lubricity are determined by the market. Since the beginning of the 500 ppm sulfur highway diesel program in 1993, refiners, engine manufacturers, engine component manufacturers, and the military have been working with ASTM

[141] Chevron Products Diesel Fuel Technical Review provides a discussion of the impacts on fuel lubricity of current diesel fuel compositional requirements in California versus the rest of the nation; *see http://www.chevron.com/prodserv/fuels/bulletin/diesel/l2%5F7%5F2%5Frf.htm.*

[142] The cost from the increased use of lubricity additives in 500 ppm NRLM diesel fuel in 2007 and in 15 ppm nonroad diesel fuel in 2010 and locomotive and marine diesel fuel in 2012 is discussed in section VI of this preamble.

[143] *See* chapter 5 of the RIA for a discussion of the potential impacts on fuel lubricity of this proposal.

[144] Nonroad and highway diesel engines meeting similar emissions standards use similar fuel systems provided by common suppliers. For example, a nonroad engine meeting the 2001 Tier 2 nonroad diesel engine emission standards would have the same fuel system as a highway diesel engine meeting the 1998 highway diesel engine emissions standards.

to develop protocols and standards for diesel fuel lubricity in its D 975 specifications for diesel fuel. ASTM is working towards a single lubricity specification that is applicable to all diesel fuel used in any type of engine. Although ASTM has not yet adopted specific protocols and standards, refiners that supply the U.S. market have been treating diesel fuel with lubricity additives on a batch by batch basis, when poor lubricity fuel is produced. ASTM's target implementation date for this specification is January 1, 2005.

The potential need for lubricity additives in diesel fuel meeting a 15 ppm sulfur specification was evaluated during the development of EPA's highway diesel rule. In response to the proposed highway diesel rule, all comments submitted regarding lubricity either stated or implied that the proposed sulfur standard of 15 ppm would likely cause the refined fuel to have lubricity characteristics that would be inadequate to protect fuel injection equipment, and that mitigation measures such as lubricity additives would be necessary. However, the commenters suggested varied approaches for addressing lubricity. For example, some suggested that we need to establish a lubricity requirement by regulation while others suggested that the current voluntary, market based system would be adequate. The Department of Defense recommended that we encourage the industry (ASTM) to adopt lubricity protocols and standards before the 2006 implementation date of the 15 ppm sulfur standard for highway diesel fuel.

The final highway diesel rule did not establish a lubricity standard for highway diesel fuel. We believe the issues related to the need for diesel lubricity in fuel used in nonroad diesel engines are substantially the same as those related to the need for diesel lubricity for highway engines. Consequently, we expect the same industry-based voluntary approach to ensuring adequate lubricity in nonroad diesel fuels that we recognized for highway diesel fuel. We believe the best approach is to allow the market to address the lubricity issue in the most economical manner, while avoiding an additional regulatory scheme. A voluntary approach should provide adequate customer protection from engine failures due to low lubricity, while providing the maximum flexibility for the industry. This approach would be a continuation of current industry practices for diesel fuel produced to meet the current federal and California 500 ppm sulfur highway diesel fuel specifications, and benefits from the considerable experience gained since 1993. It would also include any new specifications and test procedures that we expect would be adopted by ASTM regarding lubricity of NRLM diesel fuel quality.

In any event, this is an issue that will be resolved to meet the demands of the highway diesel market, and whatever resolution is reached for highway diesel fuel could be applied to NRLM diesel fuel with sufficient advance notice. We are continuing to participate in the ASTM Diesel Fuel Lubricity Task Force [145] and will assist their efforts to finalize a lubricity standard. We are hopeful that ASTM can reach a consensus this summer at the next meeting of the ASTM's Lubricity Task Force. If for some reason ASTM does not take action to set a lubricity specification, EPA will consider taking appropriate action to ensure 15 ppm sulfur diesel fuel has adequate lubricity.

3. What Other Impact Would Today's Actions Have on the Performance of Diesel and Other Fuels?

We do not expect that the fuel program finalized today will have any negative impacts on the performance of diesel engines in the existing fleet which would use the fuels regulated today.

While the process of lowering sulfur levels to 500 ppm does lower polynuclear aromatic hydrocarbons (PNAs) and total aromatics in general, it does not achieve the near-zero levels previously seen in California. The 15 ppm sulfur standard will further reduce PNAs, however, in most diesel fuel, there will still be PNAs present. Furthermore, since the 1990's, diesel engine manufacturers have switched to alternative materials (such as Viton), which do not experience leakage when PNAs are reduced. We believe that there will be no issues with leaking fuel pump O-rings with the changes in diesel fuel sulfur levels required by this rulemaking.

The moderate reduction in PNAs and total aromatics associated with the hydrotreating of diesel fuel will tend to increase the cetane index and number of diesel fuel. This will improve the driveability of vehicles operating on this higher cetane diesel fuel.

We do not expect any negative impacts on other fuels, such as jet fuel or heating oil. We do expect that the sulfur levels of heating oil may decrease because of this rulemaking. Beginning in mid-2007, we expect that controlling NRLM diesel fuel to 500 ppm sulfur will lead many pipelines to discontinue carrying high sulfur heating oil as a separate grade. In areas served by these pipelines, heating oil users will likely switch to 500 ppm sulfur diesel fuel. This will reduce emissions of SO_2 and sulfate PM from furnaces and boilers fueled with heating oil. The primary exception to this will likely be the Northeast, where a distinct higher sulfur heating oil will still be distributed as a separate fuel. Also, we expect that a small volume of moderate sulfur distillate fuel will be created during distribution from the mixing of low sulfur diesel fuels and higher sulfur fuels, such as jet fuel in the pipeline interface. Such moderate sulfur distillate will often be sold by the terminal as high sulfur heating oil, but in fact its sulfur level will be lower than that normally sold as heating oil.

H. Refinery Air Permitting

Prior to beginning diesel desulfurization projects, some refineries may be required to obtain a preconstruction permit, under the New Source Review (NSR) program, from the applicable state/local air pollution control agency.[146] We believe that today's program provides sufficient lead time for refiners to obtain any necessary NSR permits well in advance of the applicable compliance dates.

Given that today's diesel sulfur program provides roughly three years of lead time before the 500 ppm standard takes effect, we believe refiners will have time to obtain any necessary preconstruction permits. In addition, the experience gained by many refineries to obtain the preconstruction permits needed to comply with the Tier 2 and highway diesel fuel programs should benefit them in obtaining the necessary permits to comply with today's new diesel fuel requirements. Nevertheless, we believe it is reasonable to continue our efforts under the Tier 2 and highway diesel fuel programs, to help states in facilitating the issuance of permits under the NRLM diesel fuel sulfur program whenever such assistance may be needed and requested. We anticipate that such assistance may include both technical

[145] ASTM sub committee D02.E0.

[146] Hydrotreating diesel fuel involves the use of process heaters, which have the potential to emit pollutants associated with combustion, such as NO_X, PM, CO and SO_2. In addition, reconfiguring refinery processes to add desulfurization equipment could increase fugitive VOC emissions. The emissions increases associated with diesel desulfurization would vary widely from refinery to refinery, depending on many source-specific factors, such as crude oil supply, refinery configuration, type of desulfurization technology, amount of diesel fuel produced, and type of fuel used to fire the process heaters.

and procedural assistance as would be provided by the appropriate EPA Regional and Headquarters offices. Finally, to facilitate the processing of permits, we encourage refineries to begin discussions with permitting agencies and to submit permit applications as early as possible.

V. Nonroad, Locomotive and Marine Diesel Fuel Program: Details of the Compliance and Enforcement Provisions

As with earlier fuel programs, we have developed a comprehensive set of compliance and enforcement provisions designed to promote effective and efficient implementation of this fuel program and thus to achieve the full environmental potential of the program. The compliance provisions under today's final rule are designed to ensure that nonroad, locomotive, and marine diesel fuel sulfur content requirements are met throughout the distribution system, from the refiner or importer through to the end user, subject to certain provisions applicable during the early transition years. Section IV above describes our program for the reduction of sulfur in nonroad, locomotive and marine (NRLM) diesel fuel including the standards and basic design of the compliance and enforcement program. This section contains additional details regarding the compliance and assurance program. The provisions discussed in this section fall into several broad categories:

—Special fuel provisions and exemptions;
—Additional provisions applicable to refiners and importers;
—Additional provisions applicable to parties downstream of the refinery or importer;
—Special provisions regarding additives, kerosene, and the prohibition against the use of motor oil in fuel;
—Fuel testing and sampling requirements;
—Records required to be kept, including those applying under the designate and track, credit provisions, small refiner, and refiner hardship provisions;
—Reporting requirements;
—Exemptions from the program;
—Provisions concerning liability, defenses, and penalties for noncompliance; and
—The selection of the marker for heating oil and 500 ppm sulfur LM diesel fuel. (The specific requirements with respect to heating oil and 500 ppm sulfur LM diesel fuel inside and outside of the Northeast/Mid-Atlantic Area are discussed in section IV.D.)

A. Special Fuel Provisions and Exemptions

As discussed in section IV.A.1 above, the sulfur standards in today's rule generally cover all the diesel fuel that is intended for use in or used in nonroad, locomotive, and marine (NRLM) applications that is not already covered by the standards for highway diesel fuel. For the purposes of this preamble, this fuel is defined primarily by the type of engine which it is used to power: Land-based nonroad, locomotive, and marine diesel engines. Section IV.A.1 above also describes several types of petroleum distillate that are not covered by the sulfur standards promulgated today, including jet fuel and heating oil, provided they are not used in NRLM engines. The following paragraphs discuss several provisions and exemptions for NRLM diesel fuel that will apply in special circumstances.

1. Fuel Used in Military Applications

NRLM diesel fuel used in military applications is treated in the same manner as under the recent highway diesel rule. Refiners are not required to produce these fuels to the NRLM standards. However, at the same time, their use is limited only to certain military applications. NRLM diesel fuel is defined so that JP–5, JP–8, F76, and any other military fuel that is used or intended for use in NRLM diesel engines or equipment is initially subject to all of the requirements applicable to NRLM diesel fuel. However, today's rule also exempts these military fuels from the diesel fuel sulfur content and other requirements in certain circumstances. First, these fuels are exempt if they are used in tactical military motor vehicles or nonroad engines, or equipment that have a national security exemption from the vehicle or engine emissions standards. Due to national security considerations, EPA's existing regulations allow the military to request and receive national security exemptions (NSE) for their motor vehicles and NRLM diesel engines and equipment from emissions regulations if the operational requirements for such vehicles, engines, or equipment warrant such an exemption. This final rule does not change these provisions. Fuel used in these applications is exempt. Second, these fuels are also exempt if they are used in tactical military vehicles, engines, or equipment that are not covered by a national security exemption but, for national security reasons (such as the need to be ready for immediate deployment overseas), these vehicles, engines, and equipment need to be fueled on the same fuel as vehicles, engines, or equipment with a national security exemption. Use of JP–5, JP–8, F76, or any other fuel not meeting NRLM diesel fuel standards in a motor vehicle or NRLM diesel engine or equipment other than the those described above is prohibited under today's rule.

EPA and the Department of Defense have developed a process to address the tactical vehicles, engines, and equipment covered by the diesel fuel exemption and are discussing whether changes to it might be appropriate. Based on data provided by the Department of Defense to date in the context of implementing a similar exemption provision in the highway program, EPA believes that providing an exemption for military fuel used in tactical nonroad engines and equipment will not have any significant environmental impact.

The Department of Defense (DoD) commented that EPA should reconsider its determination that the definition of diesel fuel includes JP8 and JP5. DoD cited a 1995 letter from EPA which stated that there was insufficient reason to conclude that JP–8 is commonly and commercially known as diesel fuel under the then applicable definition of motor vehicle diesel fuel. Since the time of this letter, EPA has become aware of a substantial number of cases of the misuse of aviation turbine fuel in highway engines. The potential for misuse of JP–8 or similar fuels in NRLM equipment where no national security exemption exists would remain. To ensure that NRLM equipment is properly fueled with low sulfur fuel, the definition of NRLM diesel fuel has been written to encompass all diesel or other distillate fuels used or intended for use in NRLM engines, which would include JP–8 and JP–5. Furthermore, the provisions in today's rule allow vehicles, engines, and equipment to be fueled with military specification fuels that are exempt from the sulfur standards when needed for national security. We believe that this provides DoD with the needed flexibility to meet its goals of keeping vehicles, engines, and equipment ready for quick deployment overseas.

2. Fuel Used in Research, Development, and Testing

Today's final rule permits parties to request an exemption from the sulfur or other standards for NRLM diesel fuel used for research, development and testing purposes ("R & D exemption"). We recognize that there may be legitimate research programs that require the use of diesel fuel with higher sulfur levels than allowed under today's rule. As a result, this final rule contains provisions for obtaining an exemption from the prohibitions for persons, producing, distributing, transporting, storing, selling, or dispensing NRLM diesel fuel that exceeds the standards, where such diesel fuel is necessary to conduct a research, development, or testing program.

Parties seeking an R & D exemption must submit an application for exemption to EPA that describes the purpose and scope of the program, and the reasons why higher-sulfur diesel fuel is necessary. Upon presentation of the required information, an exemption can be granted at the discretion of the Administrator, with the condition that EPA can withdraw the exemption in the event the Agency determines the exemption is not justified. In addition, an exemption based on false or inaccurate information will be considered void *ab initio*. Fuel subject to an exemption is exempt from certain provisions of this rule, including the sulfur standards, provided certain requirements are met. These requirements include the segregation of the exempt fuel from non-exempt NRLM and highway diesel fuel, identification of the exempt fuel on PTDs, pump labeling, and where appropriate, the replacement, repair, or removal from service of emission systems damaged by the use of the high sulfur fuel.

3. Fuel Used in Racing Equipment

There are no provisions for an exemption from the sulfur or other content standard and other requirements for diesel fuel used in racing in today's final rule. Under certain conditions, racing vehicles are not considered nonroad vehicles. See, for example, 40 CFR § 89.2, definition of "nonroad vehicle." The fuel used by such racing vehicles would not necessarily be considered nonroad diesel fuel. However, we believe that there is a realistic chance that such fuel also could be used in NRLM equipment, and therefore, should be considered NRLM diesel fuel. We received no comments supporting the need for an exemption for racing fuel. We are not aware of any advantage for racing vehicles or racing equipment to use fuel having higher sulfur levels than are required by this rule, and we are concerned about the potential for misfueling of nonroad equipment and motor vehicles that could result from having a high sulfur (*e.g.*, 3,000 ppm) fuel for vehicle or nonroad equipment available in the marketplace. Consequently, as was the case with the highway diesel rule, this final rule does not provide an exemption from the nonroad diesel fuel requirements for fuel used in racing vehicles or equipment.

4. Fuel for Export

Fuel produced for export, and that is actually exported for use in a foreign country, is exempt from the fuel content standards and other requirements of this final rule. Such fuel will be considered as intended for use in the U.S. and subject to the standards in today's rule unless it is designated by the refiner as for export only and PTDs state that the fuel is for export only. Fuel intended for export must be segregated from all fuel intended for use in the U.S., and distributing or dispensing such fuel for domestic use is illegal.

B. Additional Requirements for Refiners and Importers

The primary requirements for refiners and importers under today's final rule are discussed in section IV above. In that section, we discuss the general structure of the compliance and enforcement provisions applicable to refiners and importers, including fuel content standards, fuel volume designation and tracking provisions, and credit provisions. In this subsection, we discuss several additional requirements for refiners and importers that are not addressed in section IV. In addition, sections V.G, V.H, and V.I below discuss several provisions that apply to all parties in the diesel fuel production and distribution system, including refiners and importers.

1. Transfer of Credits

This final rule includes provisions for NRLM diesel sulfur credit transfers that are essentially identical to other fuels rules that have credits provisions. As in other fuels rules, NRLM diesel sulfur credits can only be transferred between the refiner or importer generating the credits and the refiner or importer using the credits. If a credit purchaser can not use all the credits it purchased from the refiner who generated them, the credits can be transferred one additional time. We recognize that there is potential for credits to be generated by one party and subsequently purchased and used in good faith by another party, where the credits are later found to have been calculated or created improperly, or otherwise found to be invalid. As with the reformulated gasoline rule, the Tier 2/Gasoline Sulfur rule, and the highway diesel sulfur rule, invalid credits purchased in good faith are not valid for use by the purchaser. To allow such use would not be consistent with the environmental goals of the regulation. In addition, both the seller and purchaser of invalid credits must adjust their credit calculations to reflect the proper credits and either party (or both) can be deemed in violation if the adjusted calculations demonstrated noncompliance. We expect that the parties to such a credit transaction will develop contractual provisions to address these circumstances.

Nevertheless, in a situation where invalid credits are transferred, our strong preference will be to hold the credit seller liable for the violation, rather than the credit purchaser. As a general matter we expect to enforce a shortfall in credit compliance calculations against the credit seller, and we expect to enforce a compliance shortfall (caused by the good faith purchase of invalid credits) against a good faith purchaser only in cases where we are unable to recover sufficient valid credits from the seller to cover the shortfall. Moreover, in settlement of such cases we will strongly encourage the seller to purchase credits to cover the good faith purchaser's credit shortfall. EPA will consider the covering of a credit deficit through the purchase of valid credits a very important factor in mitigation of any case against a good faith purchaser, whether the purchase of valid credits is made by the seller or by the purchaser.

2. Additional Provisions for Importers and Foreign Refiners Subject to the Credit Provisions or Hardship Provisions

Since this final rule includes several compliance options that can be used by NRLM diesel fuel importers and foreign refiners, we are also finalizing specific compliance and enforcement provisions to ensure compliance for imported NRLM diesel fuel. These additional foreign refiner provisions are similar to those under the gasoline anti-dumping regulations, the gasoline sulfur regulations and the highway diesel fuel regulations (*see* 40 CFR 80.94, 80.410, and 80.620).

Under today's final rule, the per gallon standards for NRLM diesel fuel produced by refineries owned by foreign refiners must be met by the importer, unless the foreign refiner has been approved to produce NRLM diesel fuel under the credit provisions, small refiner provisions or hardship provisions of this final rule. If the foreign refiner is approved under any of these provisions, the volume and other requirements must be met by the foreign refiner for its refinery(s) and the foreign refiner must be the entity(s) generating, using, banking or trading any credits for the NRLM diesel fuel produced for and imported into the U.S. Importers themselves are not eligible for small refiner or hardship relief as they do not face the same capital cost and lead-time issues faced by refiners. Importers may participate in the credit programs, however, an importer and a foreign refiner may not generate credits for the same fuel.

Any foreign refiner that produces NRLM diesel fuel subject to the credit provisions, small refiner provisions or the hardship provisions will be subject to the same requirements as domestic refiners operating under the same provisions. Additionally, provisions for foreign refiners exist that are similar to the provisions at 40 CFR 80.94, 80.410, and 80.620, which include:

—Segregation of NRLM diesel fuel produced at the foreign refinery until it reaches the U.S. and separate tracking of volumes imported into each PADD;
—Controls on product designation;
—Load port and port of entry testing; and
—Requirements regarding bonds and sovereign immunity.

These provisions will aid the Agency in tracking NRLM diesel fuel from the foreign refinery to its point of import into this country. We believe these provisions are necessary and sufficient to ensure that foreign refiners' compliance can be monitored and that the diesel fuel requirements in today's rule can be enforced against foreign refiners.

3. Diesel Fuel Treated as Blendstock (DTAB)

Under today's program, a situation could arise for importers where fuel that was expected to comply with the 15 ppm sulfur NRLM standard is found to be slightly higher in sulfur than the standard. Rather than require that importer to account for, and report, that fuel as 500 ppm sulfur fuel, an importer will be able to designate the non-complying fuel as blendstock—"diesel fuel treated as blendstock" or DTAB—rather than as NRLM diesel fuel. In its capacity as a refiner, the party can then blend this DTAB fuel with lower sulfur diesel fuel or with other blendstocks to cause the sulfur level of the combined product to meet the 15 ppm sulfur NRLM diesel fuel standard prior to delivery to another entity. The same situation exists with respect to compliance with the 15 ppm sulfur highway standard. However, no provision was made in the 2007 highway final rule for this. Consequently, we are also finalizing these DTAB provisions in this final rule for application to 15 ppm sulfur highway diesel fuel.

Where diesel fuel that has been previously designated by a refiner is used to reduce the sulfur level of the DTAB to 15 ppm or less, the party, in its refiner capacity, is required to report only the volume of the imported DTAB as the amount of diesel fuel produced.[147] This avoids the double counting that would result if the same diesel fuel is reported twice (*i.e.*, once by the refiner who originally produced it and again by the refiner using it to blend with DTAB). If the product that is blended with the DTAB is not previously designated diesel fuel, but is also blendstock, the total combined volume of the DTAB and other blendstock constitutes the batch produced.

When an importer classifies diesel fuel as DTAB, that DTAB does not count toward the importer's calculations under the highway diesel rule's temporary compliance option, toward credit generation or use, or for volume account balance compliance calculations (*see* section IV).[148] The same party, however, must include the DTAB in such calculations in its capacity as a refiner. We believe such an approach will increase the supply of 15 ppm sulfur fuel by reducing the volume of near-compliant fuel that is downgraded to higher sulfur designations. In essence, it allows importers the same flexibility that refiners have within their refinery gate.

Similar to the provisions discussed above regarding the manufacture of 15 ppm sulfur diesel fuel using DTAB, 500 ppm sulfur NRLM and highway diesel fuel can also be manufactured using DTAB provided that this is appropriately reflected in the importer's compliance calculations.

C. Requirements for Parties Downstream of the Refinery or Import Facility

In order for the environmental benefits of the NRLM diesel program to be realized, parties in the fuel distribution system downstream of the refinery (including pipelines, terminals, bulk plants, wholesale purchaser-consumers, and retailers [149]) must ensure that the sulfur level of fuels supplied to the various end-users covered by today's rule complies with the requirements in today's rule. At certain points in the distribution system, such parties must keep the various grades of fuel having different sulfur specifications physically separate,[150] and ensure that the fuel is properly designated and labeled. In other words, fuel represented as 15 ppm sulfur must comply with the 15 ppm sulfur standard, and fuel represented as 500 ppm sulfur must meet the 500 ppm sulfur standard. At other points in the distribution system, certain fuels may be commingled provided that the fuel volumes are appropriately designated and accounted for in the custody holders volume account balance. Owners and operators of NRLM diesel equipment must also use fuels meeting specific sulfur content standards. The following paragraphs discuss several provisions that apply to these parties: Distribution of various fuel sulfur grades; diesel fuel pump labeling; use of used motor oil in diesel fuel; use of kerosene in diesel fuel; use of additives in diesel fuel; requirements for end users; and provisions covering downgrading of undyed diesel fuel to different grades of fuel. These provisions are analogous to similar provisions that apply to highway diesel fuel under the highway program. Section IV discusses in detail the provisions applicable to downstream parties under the designate and track program.

1. Product Segregation and End Use Requirements

The main requirements for compliance with the fuel sulfur standards under today's rule, including the designate and track provisions, are discussed in section IV of today's preamble. The sulfur content of all fuels subject to the sulfur requirements in today's rule must be appropriately

[147] Volumes of previously designated diesel fuel would be reported as volumes received under the designate and track provisions of Section IV.D.

[148] Importer/refiners availing themselves of the DTAB provisions are still subject to the downgrading provisions, and other provisions applicable to any importer or refiner.

[149] An owner/operator of a tanker truck that delivers fuel directly from the tanker truck tank into motor vehicles or nonroad equipment of another business entity (*i.e.* a mobile refueler) would be acting as a retailer, and the truck would be operating as a retail outlet. In other words, the term retail outlet is not limited to stationary facilities. EPA proposed specific textual changes to the definition of retail outlet to clarify this, but has decided there is no need to change the definition, as it has always had this plain meaning. The owner/operator of such a tanker truck may also be subject to distributor requirements and prohibitions, or carrier responsibilities if the trucker company does not take title to the fuel. As the definitions in 40 CFR 80.2 make clear, it is the functions performed by the owner/operator that determine whether they come within the scope of the applicable definitions, and the resulting obligations or requirements that apply. Mobile refuelers are not subject to the labeling requirements applicable to other retailers but are required to provide PTDs to their customers.

[150] For example: Once the required marker is added to heating oil at the terminal, heating oil must be segregated from all other fuel grades. Once red dye is added to NRLM it must be segregated from highway diesel fuel.

represented (designated/classified/labeled) at all times through to the retailer or wholesale purchaser consumer. Furthermore, the designation and classification information on the label and PTD, and the actual sulfur content of any subject fuel must be consistent with the requirements detailed in section IV. Section IV also details how to accurately redesignate, reclassify, and re-label fuel volumes. This subsection discusses the various grades and uses of NRLM fuel under the NRLM diesel program. In later subsections, we discuss related requirements for PTDs to identify fuels throughout the distribution system and provisions relating to the liability that all parties in the distribution face for failing to maintain the standards of these different fuel sulfur grades.

a. The Period From June 1, 2007 Through May 31, 2010

From June 1, 2007 through May 31, 2010, all fuel used in NRLM equipment must meet a 500 ppm sulfur standard except for fuel produced or imported under the hardship, small refiner, and credit provisions.[151] Outside of the Northeast/Mid-Atlantic Area and Alaska, we will not be able to rely upon the measurement of sulfur content alone to enforce the segregation requirements for heating oil, and are therefore requiring that heating oil be marked before it leaves the terminal by the addition of 6 mg/L of SY–124. Fuel containing more than 0.1 mg/L of the marker will be deemed to be heating oil and may not be used as nonroad, locomotive or marine fuel.

NRLM fuel designated or labeled as 500 ppm sulfur must meet the 500 ppm sulfur standard and any fuel designated or labeled as 15 ppm must meet the 15 ppm sulfur standard.[152] If a fuel meeting these standards is mixed or contaminated with a higher sulfur fuel it must be downgraded to the higher sulfur product and new documentation (*e.g.*, PTD, label) must be created to reflect the downgrade. During this period there will also be nonroad equipment that is expected to be equipped with sulfur sensitive emissions control technology that needs to operate on 500 ppm sulfur or less fuel in order to meet the NRLM program's emission standards in-use. Fuels sold for use in, or dispensed into, these engines must be identified as meeting the 15 ppm sulfur standard or the 500 ppm sulfur standard, as applicable, and if so identified must meet such standard. Distributors and retailers must avoid contaminating fuel represented by them on PTDs or pump labels as 15 ppm sulfur fuel or 500 ppm sulfur fuel with higher sulfur fuels. End users are required to use only the fuel grades identified as appropriate for use on the label affixed to their NRLM equipment.

b. The Period From June 1, 2010 Through May 31, 2012

Beginning June 1, 2010, all fuel used in nonroad equipment must meet a 15 ppm sulfur standard except for 500 ppm sulfur fuel produced or imported under the hardship, small refiner, and credit provisions, or downstream flexibility provisions which may continue to be used in nonroad engines produced prior to 2011. Locomotive and marine fuel will continue to be subject to the sulfur requirements applicable beginning June 1, 2007, until May 31, 2012.

During this time period, we will not be able to rely upon the measurement of sulfur content alone to enforce the segregation requirements for LM fuel and NR 500 ppm sulfur fuel outside of the Northeast/Mid-Atlantic Area and Alaska, and are therefore requiring that LM fuel produced or imported for use outside of the Northeast/Mid-Atlantic Area and Alaska be marked before it leaves the terminal by the addition of 6 mg/L of SY–124. Fuel containing more than 0.1 mg/L of the marker will be deemed to be either LM fuel or heating oil and may not be used as nonroad fuel. Fuel containing the marker that meets a 500 ppm sulfur standard will be deemed to be LM fuel, whereas fuel containing the marker with a sulfur content above 500 ppm will be deemed to be heating oil.

As discussed in section IV above, small refiners will be able to continue to produce 500 ppm sulfur nonroad fuel, through May 31, 2014. Other refiners may use credits through May 31, 2014 to continue to produce fuel to the 500 ppm sulfur nonroad diesel fuel standard. Nonroad diesel fuel meeting a 500 ppm sulfur standard may also be produced due to interface mixing in the distribution system.[153] In any case, 15 ppm sulfur diesel fuel must be segregated from 500 ppm sulfur NRLM diesel fuel throughout the distribution system including the end user, such that it maintains its designation, or it must be redesignated and labeled to its downgraded specification.[154]

Because of the sulfur sensitivity of the expected engine emission control systems beginning in model year 2011 for nonroad diesel engines, it is imperative that the distribution system segregate nonroad diesel fuel subject to the 15 ppm sulfur standard from higher sulfur distillate products, such as 500 ppm sulfur LM fuel, 500 ppm sulfur nonroad diesel fuel produced by small refiners or through the use of credits, heating oil, and jet fuel. End users are required to use only the fuel grades identified as appropriate for use on the label affixed to their NR and LM equipment.

We are also concerned about potential misfueling of engines requiring 15 ppm sulfur fuel at retail or wholesale purchaser-consumer facilities (as defined under this program), or other end-user facilities, even when segregation of 15 ppm sulfur fuel from the higher-sulfur grades of diesel fuel has been maintained in the distribution system. Thus, downstream compliance and enforcement provisions of this rule are aimed at both preventing contamination of nonroad diesel fuel subject to the 15 ppm sulfur standard (*i.e.*, fuel represented to meet that standard) and preventing misfueling of new nonroad equipment.

c. The Period From June 1, 2012 Through May 31, 2014

Beginning June 1, 2012, all fuel used in locomotive and marine equipment must meet a 15 ppm sulfur standard except for 500 ppm sulfur fuel produced or imported under the hardship, small refiner, and credit provisions, or downstream flexibility provisions. As discussed in section IV above, small refiners will be able to continue to produce 500 ppm sulfur LM fuel, through May 31, 2014. Other refiners may use credits through May 31, 2014 to continue to produce fuel to the 500 ppm sulfur LM diesel fuel standard. Locomotive, and marine diesel fuel meeting a 500 ppm sulfur standard may also be produced due to interface mixing in the distribution system indefinitely.

The marker requirement for 500 ppm sulfur LM diesel fuel expires on June 1, 2012. After June 1, 2012, only heating oil must continue to be marked and any LM diesel fuel distributed from the terminal must not contain the marker. To allow marked LM diesel fuel

[151] Fuel produced in the distribution system that meets a 500 ppm sulfur specification may be used in NRLM equipment through June 1, 2014, and in locomotive and marine equipment thereafter.

[152] This requirement becomes effective June 1, 2006 to support the anti-downgrade requirements in the highway diesel rule.

[153] Such 500 ppm sulfur downstream flexibility nonroad diesel fuel may be also be used in LM equipment since it complies with the LM sulfur standard applicable during this time period. Thus, both marked and unmarked 500 ppm sulfur fuel may be used in LM equipment during this time period.

[154] These flexibilities do not exist in the Northeast/Mid-Atlantic Area, and only the small refiner option exists in Alaska.

distributed prior to June 1, 2012 to be consumed by end-users, the downstream prohibition against LM fuel containing the marker will not become effective until October 1, 2012. Beginning October 1, 2012, LM diesel fuel at any location must contain no more than 0.1 mg/L of the marker.[155] We believe that allowing four months for downstream parties to blend down their stocks of marked LM diesel fuel with receipts of unmarked LM diesel fuel will be sufficient for such parties to comply with the prohibition against possessing LM fuel with a marker concentration greater than 0.1 mg/L.

The requirements that became effective for fuel used in nonroad equipment on June 1, 2010, will remain effective until May 31, 2014.

d. After May 31, 2014

After the small refiner, credit, and off-specification fuel flexibilites have expired, the remaining sulfur grades of diesel fuel will be 15 ppm sulfur highway and NRLM fuel, 500 ppm sulfur LM diesel fuel (produced due to interface mixing in the distribution system outside of the Northeast/Mid-Atlantic Area and Alaska), and heating oil, some of which may meet a 500 ppm sulfur standard. Product transfer documents are required to accompany the batches of such fuels which must contain the specified identifying information. Highway and NRLM diesel fuel meeting a 15 ppm sulfur specification must be segregated from 500 ppm sulfur LM diesel fuel, and heating oil. Today's rule contains provisions for the fungible shipment of LM diesel fuel with any heating oil meeting a 500 ppm sulfur cap up to the point where the fuel leaves the terminal that are similar to the provisions that allow the fungible shipment of high sulfur NRLM diesel fuel and high sulfur heating oil discussed in the previous section. Under such circumstances the designate and track and heating oil account balance requirements must be satisfied.

2. Diesel Fuel Pump Labeling To Discourage Misfueling

For any multiple-fuel program like the two-step program we are finalizing today, we believe that the clear labeling of nonroad diesel fuel pumps is vital so that end users can readily distinguish between the several grades of fuel that may be available at fueling facilities, and properly fuel their nonroad equipment. Section III.N above describes the labels that manufacturers are required to place on nonroad equipment, and the information that must be provided to nonroad equipment owners. Section VI discusses the likely benefit for many nonroad engines to utilize 500 ppm sulfur diesel fuel as soon as it becomes available in 2007. Today's final rule includes requirements for labeling fuel pump stands used to fuel NRLM equipment and highway diesel vehicles.

To help prevent misfueling of nonroad, locomotive and marine engines, and to thus ensure that the environmental benefits of the program are realized, we are finalizing pump labeling requirements similar to those adopted in the highway diesel rule (40 CFR 80.570). Today's pump dispenser labeling requirements are discussed separately according to the date they become effective: June 1, 2006, June 1, 2007, June 1, 2010, and June 1, 2014.

Today's final rule also amends the pump dispenser labeling language in the highway diesel regulations for consistency with the NRLM program. Because existing highway diesel regulations prohibit highway diesel fuel with sulfur levels above 500 ppm, the highway diesel final rule and this program have different meanings for the terms "low sulfur" and "high sulfur," and the highway diesel final rule does not use the term "ultra low-sulfur." Further, because the highway diesel final rule did not need to categorize the different uses of non-highway diesel fuel, the highway diesel final rule and this program have different meanings for the term "nonroad." [156] The amendments to the highway pump dispenser labeling language finalized by today's rule are meant to avoid confusion at the fuel pumps caused by labels that would have different meanings depending on whether the pump is dispensing highway or non-highway diesel fuel. Today's final rule adds effective dates to each paragraph of the labeling provisions of the highway diesel rule for consistency with the additional pump labeling sections of this program, and to distinguish the non-highway labeling requirement effective June 1, 2006 under the highway diesel rule from the non-highway labeling requirements of this rule that are effective in 2007.

Alternate labels to those specified in today's rule may be used if they are approved by the Administrator.

Today's rule also finalizes labeling requirements for pumps in Alaska that dispense NRLM diesel fuel and heating oil which is exempt from the red dye and fuel marker requirements which differ from the labeling requirements discussed in this section. Please refer to § 69.52(e) of the regulatory text to today's rule for these pump labeling requirements applicable in Alaska.

a. Pump Labeling Requirements that Become Effective June 1, 2006

The pump labeling requirements described in this section become effective June 1, 2006.

i. Pumps Dispensing Highway Diesel Fuel Subject to the 15 ppm Sulfur Standard

The label on pumps dispensing highway diesel fuel subject to the 15 ppm sulfur standard must read as follows:

ULTRA LOW-SULFUR HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all model year 2007 and later highway diesel vehicles and engines.

Recommended for use in all diesel vehicles and engines.

The above labeling requirement for 15 ppm sulfur highway diesel fuel continues through May 31, 2010, after which time different pump label requirements for this fuel become effective as described in section V.C.2.c.3. of this preamble.

ii. Pumps Dispensing Highway Diesel Fuel Subject to the 500 ppm Sulfur Standard

The label on pumps dispensing highway diesel fuel subject to the 500 ppm sulfur standard must read as follows:

LOW-SULFUR HIGHWAY DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in model year 2007 and later highway vehicles and engines.

Its use may damage these vehicles and engines.

Dispensing highway diesel fuel that has a sulfur content above 15 ppm is prohibited into any highway vehicle after September 30, 2010. Hence no pumps may display the above label after September 30, 2010.

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[155] Allowing four months for the LM fuel distribution system to sufficiently purge itself of marked fuel is consistent with the time allowed for LM diesel fuel to comply with a 500 ppm sulfur standard after the refinery gate 15 ppm sulfur standard for LM fuel becomes effective.

[156] In the highway diesel rule, the term "high-sulfur" means diesel fuel with a sulfur level greater than 15 ppm, whereas in this rule it means diesel fuel with a sulfur level greater than 500 ppm. In the highway diesel rule, the term "low-sulfur" means diesel fuel with a sulfur level less than or equal to 15 ppm, whereas in this rule it means diesel fuel with a sulfur level less than or equal to 500 ppm. In addition, the term "nonroad" as used in the highway diesel rule means "non-highway" (*i.e.*, all fuel that is not highway fuel), but the term "nonroad" as used in this rule does not include locomotive diesel, marine diesel and heating oil.

iii. Pumps Dispensing Diesel Fuel for Non-Highway Equipment That Does Not Meet the Standards for Motor Vehicle Diesel Fuel

The label on pumps dispensing diesel fuel for non-highway equipment that does not meet the standards for motor vehicle diesel fuel must read as follows:

NON-HIGHWAY DIESEL FUEL (May Exceed 500 ppm Sulfur)

WARNING

Federal law prohibits use in any highway vehicle or engine

Its use may damage these vehicles and engines.

This labeling requirement is effective until May 31, 2007, after which high sulfur non-highway diesel fuel must be labeled according to the provisions described in section V.C.2.b.iii and 500 ppm sulfur non-highway diesel fuel must be labeled according to the provisions described in section V.C.2.b.1. of today's preamble.

b. Pump Labeling Requirements That Become Effective June 1, 2007

As discussed in section IV, between June 1, 2007 and September 30, 2010, end users are not always required to dispense fuel meeting the 500 ppm sulfur standard into nonroad, equipment, locomotives or marine vessels. During this time period, small refiner fuel and fuel produced under the credit provisions with sulfur levels exceeding 500 ppm will continue to exist in the distribution system. During this time period, there will also be nonroad equipment with engines certified as meeting the Tier 4 emission standards (*i.e.*, engines equipped with emission controls that allow them to meet the Tier 4 standards earlier than required). Some of this equipment is expected to be equipped with sulfur sensitive technology that will need to operate on fuel with a sulfur content of 500 ppm or less to function properly. For this reason, it is important that NRLM end users be able to know the sulfur level of the fuel they are purchasing and dispensing. Therefore, fuel pump dispensers for the various sulfur grades must also be properly labeled. The following pump labeling requirements become effective from June 1, 2007:

i. Pumps Dispensing NRLM Diesel Fuel Subject to the 500 ppm Sulfur Standard

The label on pumps dispensing 500 ppm (maximum) sulfur content diesel fuel for use in NRLM engines must read as follows:

LOW-SULFUR NON-HIGHWAY DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in any highway vehicle or engine

The above labeling requirement remains effective until May 31, 2010, after which it is superceded by the requirements described below.

ii. Pumps Dispensing NRLM Diesel Fuel Subject to the 15 ppm Sulfur Standard

It is also likely that prior to June 1, 2010 some 15 ppm sulfur (maximum) diesel fuel will be introduced into the nonroad market early. Both the engine and fuel credit provisions envision such early introduction of 2011–compliant engines and 15 ppm sulfur diesel fuel. Thus, it is important that nonroad end users be able to know when they are purchasing diesel fuel with 15 ppm or less sulfur.[157] The label on pumps dispensing 15 ppm sulfur diesel fuel for use in NRLM engines must read as follows:

ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all model year 2011 and newer nonroad diesel engines.

Recommended for use in all nonroad, locomotive and marine diesel engines.

WARNING

Federal law *prohibits* use in any highway vehicle or engine.

The above labeling requirement continues until May 31, 2014, after which it is superceded by the labeling provisions described in section V.C.2.e.i of today's preamble.

iii. Pumps Dispensing Diesel Fuel With a Sulfur Content Greater Than 500 ppm for Use in Older NRLM Equipment

The label on pumps dispensing diesel fuel having a sulfur content greater than 500 ppm (for use in older nonroad, locomotive, and marine diesel engines) must read as follows:

HIGH-SULFUR NON-HIGHWAY DIESEL FUEL (May Exceed 500 ppm Sulfur)

WARNING

Federal law *prohibits* use in highway vehicles or engines

May damage nonroad, diesel engines required to use low-sulfur or ultra-low sulfur diesel fuel.

The above labeling requirement remains effective until September 30, 2010. After September 30, 2010 no pump may display this label.

iv. Pumps Dispensing Heating Oil

As discussed in section IV.B.2.b, it is necessary to segregate heating oil from NRLM diesel fuel to ensure that the fuel used in nonroad, locomotive, and marine equipment is compliant with the sulfur standards in today's rule. The label on pumps dispensing non-highway diesel fuel for use other than in nonroad, locomotive or marine engines, such as for use in stationary diesel engines or as heating oil, must read as follows:

HEATING OIL (May Exceed 500 ppm Sulfur)

WARNING

Federal law *prohibits* use in highway vehicles or engines, or in nonroad, locomotive, or marine engines.

Its use may damage these diesel engines.

The above labeling will remain effective indefinitely.

c. Pump Labeling Requirements That Become Effective June 1, 2010

Beginning October 1, 2010, all diesel fuel introduced into highway diesel vehicles, regardless of the year of manufacture, must meet the 15 ppm sulfur standard. Furthermore, with certain exceptions, fuel introduced into any nonroad engine must meet the 15 ppm sulfur standard. The exceptions are fuel allowed to meet the 500 ppm sulfur standard for use only in pre-model year 2011 nonroad engines and locomotive and marine engines, for example, small refiner nonroad diesel fuel and credit nonroad diesel fuel, as well as downgraded 15 ppm sulfur diesel fuel from the distribution system. This use of 500 ppm sulfur diesel fuel in nonroad engines will continue through September 30, 2014,[158] after which all nonroad diesel fuel must meet the 15 ppm sulfur standard. The following pump labeling requirements become effective June 1, 2010:

i. Pumps Dispensing NRLM Diesel Fuel Subject to the 500 ppm Sulfur Standard

The label on pumps dispensing 500 ppm (maximum) nonroad, locomotive, and marine diesel fuel, as discussed in section IV.B.3.b, must read as follows:

LOW-SULFUR NON-HIGHWAY DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in all model year 2011 and newer nonroad engines.

May damage model year 2011 and newer nonroad engines.

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[157] The IRS requires that 15 ppm sulfur non-highway diesel fuel must contain red dye after it leaves the terminal.

[158] Production of 500 ppm sulfur fuel under the credit provisions is allowed until June 1, 2012, but small refiner fuel subject to the 500 ppm sulfur standard can continue to be produced until June 1, 2014 and will be available to end users until September 1, 2014.

Federal Law *Prohibits* Use in any Highway Vehicle or Engine.

Recommended for use in all locomotive and marine equipment.

The above labeling requirement remains effective until September 30, 2014. After September 30, 2014, no pump may display this label.

ii. Pumps Dispensing Marked LM Fuel

The label on pumps dispensing 500 ppm sulfur locomotive, and marine diesel fuel, as discussed in section IV.B.3.b., must read as follows:

LOW-SULFUR LOCOMOTIVE AND MARINE DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in nonroad engines or in highway vehicles or engines.

The above labeling requirement remains effective until September 30, 2012. After September 30, 2012, no pump may display this label.

iii. Pumps Dispensing Highway Diesel Fuel Subject to the 15 ppm Sulfur Standard

The label on pumps dispensing highway diesel fuel subject to the 15 ppm sulfur standard of § 80.520(a)(1) must read as follows:

ULTRA LOW-SULFUR HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all highway diesel vehicles and engines.

Recommended for use in all diesel vehicles and engines.

The above labeling requirement for 15 ppm sulfur highway diesel fuel continues indefinitely.

d. Pump Labeling Requirements That Become Effective June 1, 2014

Beginning October 1, 2014, all nonroad fuel distributed to end-users is required to meet the 15 ppm sulfur standard, without exception. Locomotive and marine fuel downstream of the refinery or importer is still subject to the 500 ppm sulfur standard. The pump labels for heating oil will continue to be the same as for the period 2010 through 2014. The following pump labeling requirements become effective beginning June 1, 2014:

i. Pumps Dispensing NRLM Diesel Fuel Subject to the 15 ppm Sulfur Standard

For pumps dispensing nonroad diesel fuel the label must read as follows:

ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all nonroad diesel engines.

Recommended for use in all locomotive and marine diesel engines.

WARNING

Federal law *prohibits* use in any highway vehicle or engine.

The above labeling requirement continues indefinitely.

ii. Pumps Dispensing Locomotive and Marine Diesel Fuel Subject to the 500 ppm Sulfur Standard

For pumps dispensing locomotive or marine diesel fuel, the label must read as follows:

LOW-SULFUR LOCOMOTIVE OR MARINE DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in nonroad engines or in highway vehicles or engines.

Its use may damage these engines.

The above labeling requirement will remain effective indefinitely.

f. Nozzle Size Requirements or other Requirements To Prevent Misfueling

Like the highway diesel fuel program, the NRLM diesel fuel program does not include a nozzle size requirement. In part this is because we are not aware of an effective and practicable scheme to prevent misfueling through the use of different nozzle sizes or shapes, and in part because we do not believe that improper fueling will be a significant enough problem to warrant such an action. In the preamble to the highway diesel fuel rule, we stated our belief that the use of unique nozzles, color-coded scuff-guards, or dyes to distinguish the grades of diesel fuel may be useful in preventing accidental use of the wrong fuel. (*See* 66 FR 5119, January 18, 2001.) However, we did not finalize any such requirements, for the reasons described in the RIA for that final rule (section IV.E).

Similar reasoning applies to the NRLM diesel fuel program. For example, 15 ppm sulfur diesel fuel will be the dominant fuel in the market by 2010, likely comprising more than 80 percent of all number 2 distillate. Further, we believe that 500 ppm sulfur diesel fuel will have limited availability between 2010 and 2014. High-sulfur distillate for heating oil uses will remain, but will only exist in significant volumes in certain parts of the country. In addition, as with highway diesel engines, there is currently no standardization of fuel tank openings and filler necks that would allow for a simple, inexpensive, standardization of nozzles. In any event, we believe that most owners and operators of new nonroad diesel engines and equipment will not risk voiding the general warranty and the emissions warranty by misfueling.

Although in the highway diesel fuel rule we did not finalize any provisions beyond fuel pump labeling requirements, we recognized that some potential for misfueling could still exist. Consequently, we expressed a desire to continue to explore with industry simple, cost-effective approaches that could further minimize misfueling potential such as color-coded nozzles/ scuff guards. Since the highway diesel rule was promulgated, we have had discussions with fuel retailers, wholesale purchaser-consumers, vehicle manufacturers, and nozzle manufacturers, and continue to examine different methods for preventing accidental or intentional misfueling under the highway diesel fuel sulfur program. To date, the affected stakeholders, including engine and truck manufacturers, truck operators, fuel retailers, and fuel nozzle manufacturers have not reached any common view that the concerns over misfueling warrant any additional prevention measures.

3. Prohibition Against the Use of Used Motor Oil in New Nonroad Diesel Equipment

We understand that used motor oil is sometimes blended with diesel fuel today for use as fuel in nonroad diesel equipment. Such practices include blending used motor oil directly into the equipment fuel tank, blending it into the fuel storage tanks, and blending small amounts of motor oil from the engine crank case into the fuel system as the equipment is operated.

However, motor oil normally contains high levels of sulfur. Thus, the addition of used motor oil to nonroad diesel fuel could substantially impair the sulfur-sensitive emissions control equipment expected to be used by engine manufacturers to meet the emissions standards in today's final rule. Depending on how the oil is blended, it could increase the sulfur content of the fuel by as much as 200 ppm sulfur. As a result, we believe blending used motor oil into nonroad diesel fuel could render inoperative the expected emission control technology and potentially cause driveability problems. Consequently, it would violate the tampering prohibition in the Act. *See* CAA sections 203(a)(3), and 213(d).

Therefore, like the highway diesel rule, today's rule prohibits any person from introducing or causing or allowing the introduction of used motor oil, or diesel fuel containing used motor oil, into the fuel delivery systems of nonroad equipment engines manufactured in model year 2011 and later. The only exception to this will be where the engine was explicitly certified to the emission standard with used motor oil added and the oil was added in a manner consistent with the certification. Furthermore, as discussed in section IV, today's rule includes certain sunset dates when all NRLM diesel fuel in the distribution system must meet the applicable sulfur standard, and before that date any NRLM designated, classified, or labeled as 15 ppm sulfur fuel must meet that sulfur standard. Blending of used motor oil into NRLM could cause these standards to be exceeded in violation of today's rule. Any party who causes the sulfur content of nonroad diesel fuel subject to the 15 ppm sulfur standard to exceed 15 ppm by blending motor oil into nonroad diesel fuel, or by using motor oil as nonroad diesel fuel, is subject to liability for violating the sulfur standard. Similarly, parties who cause the sulfur level of nonroad diesel fuel subject to the 500 ppm sulfur nonroad diesel fuel standard to exceed that standard by blending motor oil into the fuel, are also subject to liability.

4. Use of Kerosene in Diesel Fuel

As we discussed in the highway diesel final rule, kerosene is commonly added to diesel fuel to reduce fuel viscosity in cold weather (*see* 66 FR 5120, January 18, 2001). This final rule does not limit this practice with regard to 15 ppm sulfur or 500 ppm sulfur NRLM diesel fuel. However the resulting blend will still be subject to the 15 ppm sulfur or 500 ppm sulfur standard. Kerosene that is used, intended for use, or made available for use as, or for blending with, 15 ppm sulfur or 500 ppm sulfur diesel fuel is itself required to meet the 15 ppm sulfur or 500 ppm sulfur standard.

As a general matter, any party who blends kerosene, or any blendstock, into NRLM diesel fuel, or who produces NRLM diesel fuel by mixing blendstocks, will be treated as a refiner and will be subject to the requirements and prohibitions applicable to refiners under today's rule. For example, the fuel that they manufacture must meet the sulfur standards established in this rule, and represented on the PTD. However, in deference to the longstanding and widespread practice of blending kerosene into diesel fuel at downstream locations, downstream parties who only blend kerosene into NRLM and highway diesel fuel will not be subject to the requirements applicable to other refiners, provided that they do not alter the fuel in any other way, and do not violate the volume balance requirements discussed in section IV.D. For example, they will not need to meet the 80/20 requirements under the highway diesel program. This activity is treated the same way under the final highway diesel rule. Parties that blend kerosene into diesel fuel are subject to the downstream designate and track provisions applicable to other downstream parties.

In order to ensure the continued compliance of 15 ppm sulfur fuel with the 15 ppm sulfur standard, downstream parties choosing to blend kerosene into 15 ppm sulfur NRLM diesel fuel are required to either have a PTD for that kerosene indicating compliance with the 15 ppm sulfur standard, or to have test results for the kerosene establishing such compliance. Further, downstream parties choosing to blend kerosene into 15 ppm sulfur NRLM diesel fuel are entitled to the two ppm adjustment factor discussed in section V.D.2. for both the kerosene and the diesel fuel into which it is blended at downstream locations, provided that the kerosene had been transferred to the party with a PTD indicating compliance with that standard. Sulfur test results from downstream locations of parties who do not have such a PTD for their kerosene will not be subject to this adjustment factor, either for the kerosene itself, or for the NRLM diesel fuel into which it is blended.

Any party who causes the sulfur content of NRLM diesel fuel represented as meeting the 15 ppm sulfur standard to exceed 15 ppm sulfur by blending kerosene into NRLM diesel fuel, or by using greater than 15 ppm sulfur kerosene as NRLM diesel fuel, is subject to liability for violating the sulfur standard. Similarly, parties who cause the sulfur level of NRLM diesel fuel subject to the 500 ppm sulfur diesel fuel standard to exceed that standard by blending kerosene into the fuel, are also subject to liability.

Today's rule does not require refiners or importers of kerosene to produce or import kerosene meeting the 15 ppm sulfur standard. However, we believe that refiners will produce ultra low sulfur kerosene in the same refinery processes that they use to produce ultra low sulfur diesel fuel, and that the market will drive supply of ultra low sulfur kerosene for those areas where, and during those seasons when, the product is needed for blending with NRLM, as well a highway, diesel fuel.

As discussed in section IV.D, kerosene blending also factors into the designate and track provisions finalized today from June 1, 2006 until June 1, 2010. During this time period it is possible, and in fact likely, that kerosene meeting the 15 ppm sulfur standard will instead be designated as No. 1 highway diesel fuel, and will simply need to meet all of the requirements of highway diesel fuel. It is also possible, though less likely that kerosene meeting the 500 ppm sulfur standard will be designated as No. 1 highway diesel fuel. However, if it is, it would also merely need to comply with all the requirements applicable to highway diesel fuel.

5. Use of Diesel Fuel Additives

Diesel fuel additives include lubricity improvers, corrosion inhibitors, cold-operability improvers, and static dissipaters. Use of such additives is distinguished from the use of kerosene or biodiesel by the low concentrations at which they are used (defined to be one percent or less) and their relatively more complex chemistry.[159] The suitability of diesel fuel additives for use in diesel fuel meeting a 500 ppm sulfur specification has been well established due to the existence of 500 ppm sulfur highway diesel fuel in the marketplace since 1993. The suitability of additives for use in 15 ppm sulfur diesel fuel was first addressed by EPA in the highway diesel program, which requires highway diesel fuel to meet a 15 ppm sulfur standard beginning in 2006. At the time of the finalization of the highway diesel final rule and during our development of the proposed NRLM diesel rule, our review of data submitted by additive and fuel manufacturers to comply with EPA's Fuel and Fuel Additive Registration requirements indicated that additives to meet every purpose, including static dissipation, are currently in common use which meet a 15 ppm cap on sulfur content.[160]

a. Additives Used in 15 ppm Sulfur Diesel Fuel

Similar to the highway diesel rule, today's rule allows the bulk addition of diesel fuel additives with a sulfur content greater than 15 ppm in NRLM diesel fuel under certain circumstances.[161] However, NRLM

[159] Diesel fuel additives are used at concentrations commonly expressed in parts per million. Diesel fuel additives can include specially-formulated polymers and other complex chemical components. Kerosene is used at much higher concentrations, expressed in volume percent. Unlike diesel fuel additives, kerosene is a narrow distillation fraction of the range of hydrocarbons normally contained in diesel fuel.

[160] *See* Chapter IV.D. of the RIA for the highway diesel fuel rule for more information on diesel fuel additives, EPA Air docket A–99–06, docket item V–B–01. *Also see* 40 CFR part 79.

[161] Most diesel fuel additives are added at the terminal to bulk fuel volumes before sale to the consumer. These additives are referred to as bulk additives. End users and wholesale purchaser consumers sometimes also add additives to diesel

Continued

diesel fuel containing such additives will continue to be subject to the 15 ppm sulfur cap. We believe that it is most appropriate for the market to determine how best to accommodate increases in fuel sulfur content from the refinery gate to the end user, while maintaining the 15 ppm sulfur cap, and whether such increases result from contamination in the distribution system or bulk diesel additive use. By providing this flexibility, we anticipate that market forces will encourage an optimal balance between the competing demands of manufacturing fuel lower than the 15 ppm sulfur cap, limiting contamination in the distribution system, and limiting the bulk additive contribution to fuel sulfur content.

Thus, as in the highway diesel program, additive manufacturers that market bulk diesel additives with a sulfur content higher than 15 ppm and blenders that use them in nonroad diesel have additional requirements to ensure that the 15 ppm sulfur cap for NRLM diesel fuel is not exceeded.

The 15 ppm sulfur cap on highway diesel fuel that becomes effective in 2006 may encourage the gradual retirement of additives that do not meet a 15 ppm sulfur cap. The 15 ppm sulfur cap for NR fuel in 2010 and for LM fuel in 2012 may further this trend. However, we do not anticipate that this will result in disruption to additive users and producers or a significant increase in cost. Additive manufacturers commonly reformulate their additives on a periodic basis as a result of competitive pressures. We anticipate that any reformulation that might need to occur to meet a 15 ppm sulfur cap, will be accomplished prior to the implementation of the 15 ppm sulfur cap on highway diesel fuel in 2006.

Like the highway diesel fuel rule, this rule will limit the continued use in 15 ppm sulfur fuel of a bulk additive that exceeds 15 ppm sulfur to a concentration of less than one volume percent. We believe that this limitation is appropriate and will not cause any undue burden because the diesel fuel additives for which this flexibility was included are always used today at concentrations well below one volume percent. Further, one volume percent is the threshold above which the blender of an additive becomes subject to all the requirements applicable to a refiner. *See* 40 CFR 79.2(d)(1) and 40 CFR part 80.

fuel by hand blending into the vehicle fuel tank or fleet fuel storage tanks. Such additives are referred to as aftermarket additives. As discussed at the end of this section, today's rule contains different requirements regarding the use of aftermarket additives.

The specific requirements regarding the use of bulk diesel fuel additives in NRLM fuel subject to the 15 ppm sulfur standard are as follows:

—Bulk additives that have a sulfur content at or below 15 ppm must be accompanied by a PTD that states: "The sulfur content of this additive does not exceed 15 ppm."

—Bulk additives that exceed 15 ppm sulfur could continue to be used in diesel fuel subject to the 15 ppm sulfur standard provided that they are used at a concentration of less than one volume percent and their transfer is accompanied by a PTD that lists the following:

(1) A warning that the additive's sulfur content may exceed 15 ppm and that improper use of the additive may result in non-complying fuel,

(2) The additive's maximum sulfur concentration,

(3) The maximum recommended concentration for use of the additive in diesel fuel, and

(4) The contribution to the sulfur level of the fuel that would result if the additive is used at the maximum recommended concentration.

We proposed that the affirmative defenses to presumptive liability for blenders of bulk additives with a sulfur content greater than 15 ppm must include periodic sulfur tests after the addition of the additive showing that the finished fuel does not exceed the 15 ppm sulfur cap. We are adopting this proposed requirement for additives other than static dissipater additives.

b. Static Dissipater Additives

Comments from diesel fuel distributors and additive manufactures stated that static dissipater additives are unique among the various types of diesel fuel additives in that there are currently none available with a sulfur content below 15 ppm which are fully effective. Considering the lack of static dissipater additives meeting a 15 ppm sulfur cap, and the inability to add static dissipater (S–D) additives prior to shipment by pipeline, commenters stated that the prohibitive cost of testing fuel batches after the addition of static dissipater additives could discourage their use. To avoid the potential adverse impact on the safety of the fuel distribution industry which could result, commenters requested that we provide an alternative method for use in demonstrating their affirmative defense to presumptive liability when they use static dissipater additives with a sulfur content above 15 ppm. Manufacturers of static dissipater additives stated that due to very low treatment rates that are needed for such additives, their use will raise the sulfur content of the finished fuel by no more than 0.02 ppm. Commenters stated that because of the extremely low potential contribution to the sulfur level of the finished diesel fuel which might result from the use of static dissipater additives, there was little risk that use of such additives would result in noncompliance with the 15 ppm sulfur cap.

We contacted all of the additive manufactures that have registered static dissipater additives in EPA's Fuel and Fuel Additive Database.[162] All of these manufactures stated that there are no fully-effective static dissipater additives available that have a sulfur content below 15 ppm. They further stated that sulfur is an essential component in static dissipater additives, and that it is currently unclear how to formulate a static dissipater additive that would have a sulfur content below 15 ppm. Because of this input, we now recognize that static dissipater additives are in a unique category with respect to the ability to comply with a 15 ppm sulfur cap. Additive manufactures stated that reformulation of static dissipater additives to meet a 15 ppm sulfur cap will likely be a lengthy undertaking.

It is unclear which of the naturally-occurring components in diesel fuel act to dissipate static electricity. However, certain batches of fuel are periodically found which do not have adequate static dissipating qualities. In such cases, static dissipater additives are necessary to prevent a static discharge from occurring during the transfer of fuel into a storage tank which might cause an explosion. Therefore, it is essential that today's rule is structured in such a way so as to not impede the use static dissipater additives. Because of the lack of static dissipater additives meeting a 15 ppm sulfur specification, the unique difficulty in reformulating them to meet a 15 ppm sulfur standard, the fact that they are essential to the safety of the fuel distribution system, and the impracticability for them to be added at the refinery, today's rule includes special affirmative defense provisions to reduce the sulfur testing burden associated with the use of static dissipater additives that have a sulfur content greater than 15 ppm.

Commenters suggested an alternative mechanism to demonstrate an affirmative defense to presumptive liability for blenders of static-dissipater (S–D) additives which would avoid the need to test every batch of fuel at the

[162] All additives must be registered with EPA Fuel and Fuel Additive Database prior to their use in motor vehicle diesel fuel.

terminal after additization. Under this approach, blenders of S–D additives would be required to provide volume accounting reconciliation (VAR) records similar to those under EPA's deposit control additive rule (40 CFR part 80, subpart G) which would show whether the S–D additive is being added at the appropriate rate on average over a course of a monthly accounting period. Today's rule finalizes the approach suggested by commenters with certain modifications. In cases where a violation of the 15 ppm sulfur cap for diesel fuel is discovered on a batch of fuel downstream of a blender of S–D additives that have a sulfur content above 15 ppm, the S–D additive blender must provide the following information to EPA in order to meet their affirmative defense to presumptive liability regarding the potential that the use of S–D additive might have caused or contributed to the violation:

• A sulfur test on the diesel batch prior to the addition of the S–D additive package that indicates that the additive, when added, will not cause the fuel to exceed 15 ppm

• A product transfer document that accompanied the transfer of the S–D additive package to the additive blender which contains the following:

—A statement that the S–D additive package exceeds 15 ppm in sulfur content and that special requirements apply if it is to be used in diesel fuel subject to the 15 ppm sulfur cap.
—The maximum sulfur level of the S–D additive package including other additive components such as diesel detergents and carrier fluid to the extent that they are part of the package. Each component of the additive package other than the S–D additive itself must comply with the 15 ppm sulfur cap.
—The maximum recommended concentration for the S–D additive package.
—The contribution to the final sulfur content of a finished fuel when the additive is added at the maximum recommended concentration. The maximum recommended concentration must result in a potential increase in the sulfur content of the finished fuel of no more than 0.05 ppm.

• Monthly volume accounting reconciliation (VAR) records that include:

—The amount of S–D additive package used during the month
—The volume of the fuel into which the additive was injected during the month
—The measured sulfur level of each fuel batch prior to injection of the additive which shows that the contribution to the sulfur level of the finished diesel fuel from the use of the additive at the treatment level at which it was injected would not cause any such batch of fuel to exceed the 15 ppm sulfur specification

• Quality assurance records which show that the precision of the additive injection equipment has been maintained in such a manner as to prevent malfunctions which could result in the injection of the S–D additive at a higher concentration than that reported.

The additive blender must also be able to meet its normal diesel fuel defense elements: That the additive blender-fuel distributor did not cause the violation; that PTDs account for all the fuel and show apparent compliance; and that quality assurance sampling and testing has occurred, as modified by the discussion above.

In addition, the ratio of the amount of additive used to the amount of fuel into which the additive was injected over any given monthly VAR period must not exceed the maximum treatment rate which could be added to any batch of fuel additized during the period. If not, the blender could be liable for any batch of diesel fuel found that exceeded the 15 ppm sulfur cap which had been in their possession. The above provisions are only relevant for establishing affirmative defense to presumptive liability regarding the potential that the use of S–D additives might have caused a violation. Under no circumstances may an additive blender cause the sulfur level of any batch of finished fuel to exceed the 15 ppm sulfur cap. Blenders of S–D additives must meet all other requirements for distributors of 15 ppm sulfur diesel fuel. Regardless of the cause of a violation of the 15 ppm sulfur standard, any party that had custody or title of off-specification fuel is potentially liable and responsible for their affirmative defense elements.

These provisions may only be used for static dissipater additives which have the potential to raise the sulfur content of the finished fuel by no more than 0.050 ppm when used at their maximum recommended treatment level. Based on the input from additive manufacturers noted above, this will allow the use of S–D additives that are fully effective for this purpose. The use of S–D additives that might have a higher contribution to the sulfur content of the finished fuel, therefore, is unnecessary. To establish affirmative defense to presumptive liability, blenders that use S–D additives that could contribute more than 0.050 ppm to the sulfur content of a finished fuel subject to the 15 ppm sulfur specification when used at the maximum recommended treatment level are required to conduct a sulfur test on the fuel batch after the addition of the additive. Blenders of additives other than S–D additives which have a sulfur content greater than 15 ppm into diesel fuel subject to the 15 ppm sulfur standard are also required to conduct a sulfur test on the fuel batch after the addition of the additive for affirmative defense purposes.

EPA may require additive manufactures to supply samples of the additive packages (or the components additives in such packages) that are used in 15 ppm sulfur diesel fuel, or may sample from additive batches already in the distribution system. In such cases, we may test the sulfur content of these additives to evaluate whether they are in compliance with the information provided on the PTDs or other relevant documentation. In cases where a violation is discovered, any party in the distribution system that had custody of the additive batch found to be in violation may be held presumptively liable for the violation.

Today's rule amends the highway diesel regulation so that the provisions finalized today regarding the use of S–D additives with a sulfur content above 15 ppm in NRLM diesel fuel also apply to the use of such additives in highway diesel fuel subject to a 15 ppm sulfur standard. However, we continue to be concerned about the use of additives having a sulfur content greater than 15 ppm. We will continue to monitor this issue and may initiate an additional rulemaking in the future to consider further limiting or prohibiting the use of greater than15 ppm sulfur additives in diesel fuel subject to a 15 ppm sulfur cap.

The special provisions for static-dissipater additives finalized in today's rule will ensure that the unique challenges regarding the manufacture and use of such additives do not present a barrier to their continued use. Additive manufactures have stated that they are working on reformulation of their S–D additives to meet a 15 ppm sulfur limit.

We recently learned that industry is beginning to develop a standardized test to quantify the concentration of static-dissipater additives in finished fuel.[163] If such a test were available, it might be useful for establishing an additive blender's affirmative defense to presumptive liability in place of some of the VAR provisions described above. If

[163] Phone conversation with Eon McMullen, Octel additives, February 12, 2004.

a batch of fuel was found to exceed the 15 ppm sulfur cap, the use of such a test would allow for the measurement of the contribution to the sulfur level of the finished fuel which resulted from the addition of the static dissipater additive. If the contribution was below the permissible level given the sulfur measurements on each batch of fuel additized with the greater than 15 ppm S–D additive, it might be useful in association with other blender records to demonstrate that the additive blender was not at fault for the violation. If such a standardized test becomes available, EPA will work with the appropriate industry parties to evaluate its applicability for affirmative defense purposes, and conduct a rulemaking if appropriate to amend the elements required to establish affirmative defense to presumptive liability under the NRLM and highway diesel programs.

c. Additives Used in 500 ppm Sulfur Diesel Fuel

The 1993 and 2007 highway diesel programs did not contain any requirements regarding the maximum sulfur content of additives used in highway diesel fuel subject to a 500 ppm sulfur cap.[164] Our experience under the highway program indicates that application of the 500 ppm sulfur cap throughout the distribution system to the end-user has been sufficient to prevent the use of additives from jeopardizing compliance with the 500 ppm sulfur standard. The potential increase of several ppm in the sulfur content of diesel fuel which might result from the use of some diesel additives raises substantial concerns regarding the impact on compliance with a 15 ppm sulfur cap. However, this is not the case with respect to the potential impact on compliance with a 500 ppm sulfur cap. The current average sulfur content of highway diesel fuel of 340 ppm provides ample margin for the minimal increase in the fuel sulfur content which might result from the use of additives. We expect that this will also be the case for NRLM fuel subject to the 500 ppm sulfur standard. Therefore, we are not finalizing any requirements regarding the sulfur content of additives used in NRLM fuel subject to the 500 ppm sulfur standard. We believe that the requirement that NRLM fuel comply with a 500 ppm sulfur cap throughout the distribution system to the end-user will be sufficient to ensure that entities who introduce additives into such fuel take into account the potential increase in fuel sulfur content.

d. Aftermarket Additives

We believe that more stringent requirements are needed for aftermarket additives than for bulk additives due to the lack of practical safeguards to ensure that the use of such additives do not cause a violation of the sulfur standards in today's rule. Also, the presence of multiple grades of aftermarket additives, some suitable for use in engines equipped with sulfur sensitive emissions control equipment as well as pre-control engines, and some suitable for use only in pre-control engines would raise significant concerns regarding the misuse. The misuse of a high sulfur additive in an engine with sulfur sensitive emissions control equipment could damage this equipment. Therefore, today's rule requires that all aftermarket additives sold for use in nonroad, locomotive, and marine equipment must meet a 500 ppm sulfur cap beginning June 1, 2007, and that all aftermarket additives sold for use in nonroad equipment must meet a 15 ppm sulfur specification beginning June 1, 2010. After June 1, 2010, aftermarket additives with a sulfur content less than 500 ppm may continue to be used in locomotive and marine engines. This approach is consistent with that taken in the highway diesel rule which requires all aftermarket additives to meet a 15 ppm sulfur specification beginning June 1, 2006.

6. End User Requirements

In light of the importance of ensuring that the proper fuel is used in nonroad, locomotive, and marine engines covered by this program, any person is prohibited from fueling such an engine with fuel not meeting the applicable sulfur standard.

Specifically:

(1) No person may introduce, or permit the introduction of fuel containing the heating oil marker into nonroad, locomotive, marine or highway diesel engines;

(2) No person may introduce, or permit the introduction of, fuel that exceeds 15 ppm sulfur content into nonroad equipment with a model year 2011 or later engine;

(3) Beginning December 1, 2010, no person may introduce, or permit the introduction of any fuel exceeding 500 ppm sulfur content into any nonroad, locomotive, and marine engine; and

(4) Beginning December 1, 2014, no person may introduce, or permit the introduction of any fuel exceeding 15 ppm sulfur content into any nonroad diesel engine regardless of year of manufacture.

D. Diesel Fuel Sulfur Sampling and Testing Requirements

1. Testing Requirements

Today's action provides a new approach for fuel sulfur measurement. The details of this approach are described below, followed by a description of who will be required to conduct fuel sulfur testing as well as what fuel must be tested. The diesel fuel sulfur sampling and testing provisions described below are similar to those that were proposed. Adjustments we made to the proposed provisions were in response to comments we received during the public comment period.

a. Test Method Approval, Record-keeping, and Quality Control Requirements

Most current and past EPA fuel programs designated specific analytical methods which refiners, importers, and downstream parties [165] use to analyze fuel samples at all points in the fuel distribution system for regulatory compliance purposes. Some of these programs have also allowed certain specific alternative methods which may be used as long as the test results are correlated to the designated test method. The highway diesel rule (66 FR 5002, January 18, 2001), for example, specifies one designated test method and three alternative methods for measuring the sulfur content of highway diesel fuel subject to the 15 ppm sulfur standard. The rule also specifies one designated method and three alternative methods for measuring the sulfur content of highway diesel fuel subject to the 500 ppm sulfur standard.

[164] The 500 ppm sulfur highway diesel final rule contains the requirement that highway diesel fuel not exceed 500 ppm sulfur at any point in the fuel distribution system including after the blending of additives. Fuel Quality Regulations for Highway Diesel Fuel Sold in 1993 and Later Calendar Years, Final Rule, 55 FR 34120, August 21, 1990.

[165] Other EPA fuels regulations have allowed downstream parties conducting periodic quality assurance testing for defense purposes to use methods other than the designated method, so long as the method is an ASTM method appropriate for testing for the applicable fuel property, and so long as the instrument is correlated to the designated method.

TABLE V.H–1.—DESIGNATED AND ALTERNATIVE SULFUR TEST METHODS ALLOWED UNDER THE HIGHWAY DIESEL PROGRAM

Sulfur Test Method	500 ppm	15 ppm
ASTM D 2622–03, as modified, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry.	Designated	Alternative.
ASTM D 3120–03a, Standard Test Method for Trace Quantities of Sulfur in Light Liquid Petroleum Hydrocarbons by Oxidative Microcoulometry.		Alternative.
ASTM D 4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry.	Alternative	
ASTM D 5453–03a, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Motor Oils by Ultraviolet Fluorescence.	Alternative	Alternative.
ASTM D 6428–99, Test Method for Total Sulfur in Liquid Aromatic Hydrocarbons and Their Derivatives by Oxidative Combustion and Electrochemical Detection.	Alternative	Designated.

The highway diesel fuel rule also announced the Agency's intention to adopt a performance-based test method approach in the future, as well as our intention to continue working with the industry to develop and improve sulfur test methods. Today's action adopts such a performance-based test method approach for both highway and NRLM diesel fuel subject to the 15 ppm and 500 ppm sulfur standards. In addition, the current approach for measuring the sulfur content of diesel fuel subject to the 500 ppm sulfur standard, *i.e.*, using the designated sulfur test method or one of the alternative test methods with correlation will remain applicable.

Under the performance-based approach, a given test method can be approved for use in a specific laboratory by meeting certain precision and accuracy criteria specified in the regulations. The method can be approved for use by that laboratory as long as appropriate quality control procedures are followed. Properly selected precision and accuracy values allow multiple methods and multiple commercially available instruments to be approved, thus providing greater flexibility in method and instrument selection while also encouraging the development and use of better methods and instrumentation in the future. Under today's rule, there is no designated sulfur test method as specified under previous regulations.

Since any test method that meets the specified performance criteria may qualify, this type of approach does not conflict with the "National Technology Transfer and Advancement Act of 1995" (NTTAA), section 12(d) of Public Law 104–113, and the Office of Management and Budget (OMB) Circular A–119. Both of these are designed to encourage the adoption of standards developed by "voluntary consensus standards bodies" (VCSB) [166] and to reduce reliance on government-unique standards where such consensus standards would suffice. Under the performance criteria approach in today's rule, methods developed by consensus bodies as well as methods not yet approved by a consensus body qualify for approval provided they meet the specified performance criteria as well as the record-keeping and reporting requirements for quality control purposes.

i. How Can a Given Method Be Approved?

A given test method can be approved for use under today's program by meeting certain precision and accuracy criteria. Approval applies on a laboratory/facility-specific basis. If a company chooses to employ more than one laboratory for fuel sulfur testing purposes, then each laboratory must separately seek approval for each method it intends to use. Likewise, if a laboratory chooses to use more than one sulfur test method, then each method must be approved separately. Separate approval is not necessary for individual operators or laboratory instruments within a given laboratory facility.

The specific precision and accuracy criteria were derived from existing sulfur test methods that are either required or allowed under the highway diesel fuel sulfur program. The first criterion, precision, refers to the consistency of a set of measurements and is used to determine how closely analytical results can be duplicated based on repeat measurements of the same material under prescribed conditions. To demonstrate the precision of a given sulfur test method under the performance-based approach, a laboratory facility must perform 20 repeat tests over 20 days on samples taken from a homogeneous supply of a commercially available diesel fuel. Based on the comments we received on this issue, we are also clarifying that the test results must in general be a sequential record of the analyses with no omissions. A laboratory facility may exclude a given sample or test result only if (1) the exclusion is for a valid reason under good laboratory practices and (2) it maintains records regarding the sample and test results and the reason for excluding them. Using the test results[167] of ASTM D 3120 for diesel fuel subject to the 15 ppm sulfur standard, the precision must be less than 0.72 ppm.[168] Similarly, using the test results of ASTM D 2622 for diesel fuel subject to the 500 ppm sulfur standard, the precision must be less than 9.68 ppm.

The second criterion, accuracy, refers to the closeness of agreement between a measured or calculated value and the actual or specified value. To demonstrate the accuracy of a given test method under the performance-based approach, a laboratory facility is required to perform 10 repeat tests on a

[166] These are standard-setting organizations, like ASTM, and ISO that have broad representation of all interested stakeholders and make decisions by consensus.

[167] Sulfur Repeatability of Diesel by Method at 15 ppm, ASTM Report on Low Level Sulfur Determination in Gasoline and Diesel Interlaboratory Study—A Status Report, June 2002.

[168] 0.72 ppm is equal to 1.5 times the standard deviation of ASTM D 3120, where the standard deviation is equal to the repeatability of ASTM D 3120 (1.33) divided by 2.77. 9.68 ppm is equal to 1.5 times the standard deviation of ASTM D 2622, where the standard deviation is equal to the repeatability of ASTM D 2622 (17.88) divided by 2.77. In the proposal, we stated that the repeatability of ASTM D 2622 was 26.81. While that reported value was incorrect due to either a typographical or a computational error, the resulting precision value that we are finalizing today was correctly calculated and reported as 9.68 ppm. The "sample standard deviation" should be used for this purpose. By its use of N–1 in the denominator, this measure applies a correction for the small sample bias and provides an unbiased estimate of the standard deviation of the larger population from which the sample was drawn. Since the conditions of the precision qualification test admit more sources of variability than the conditions under which ASTM repeatability is determined (longer time span, different operators, environmental conditions, etc.) the repeatability standard deviation derived from the round robin was multiplied by what we believe to be a reasonable adjustment factor, 1.5, to compensate for the difference in conditions.

standard sample, the mean of which for diesel fuel subject to the 15 ppm sulfur standard can not deviate from the Accepted Reference Value (ARV) of the standard by more than 0.54 ppm and for diesel fuel subject to the 500 ppm sulfur standard can not deviate from the ARV of the standard by more than 7.26 ppm [169]. These tests must be performed using commercially available gravimetric sulfur standards. Ten tests are required using each of two different sulfur standards. For 15 ppm fuel, one must be in the range of 1–10 ppm sulfur and the other in the range of 10–20 ppm sulfur. For 500 ppm fuel, one must be in the range of 100–200 ppm sulfur and the other in the range of 400–500 ppm sulfur for 500 ppm sulfur diesel fuel. Therefore, a minimum of 20 total tests is required for sufficient demonstration of accuracy for a given sulfur test method at a given laboratory facility. As with the requirement for precision demonstration described above, the test results must be a sequential record of the analyses with no omissions. Finally, any known interferences for a given test method must be mitigated.

Some commenters remarked that the ARV of the standards does not account for any uncertainty given that all commercially available standards have an uncertainty associated with the certified value. The commenters added that EPA should specify what maximum value in the uncertainty associated with the ARV is allowed.

These requirements are not intended to be overly burdensome. Indeed, we believe these requirements are equivalent to what a laboratory would do during the normal start up procedure for a given test method. In addition, we believe this approach will allow regulated entities to know that they are measuring diesel fuel sulfur levels accurately and within reasonable site reproducibility limits.

ii. What Information Must Be Reported to the Agency?

For test methods that have already been approved by a VCSB, such as ASTM or the International Standards Organization (ISO), each laboratory facility must report to the Agency the precision and accuracy results as described above for each method for which it is seeking approval. Such submissions to EPA, as described elsewhere, are subject to the Agency's review for 90 days, and the method will be considered approved in the absence of EPA comment. Laboratory facilities are required to retain the fuel samples used for precision and accuracy demonstration for 90 days. While we proposed a 30 day sample retention period, commenters stated that the sample retention period for fuel samples that are used for precision and accuracy demonstrations should be equivalent to the length of EPA's review period (*i.e.*, 90 days). We agree with the commenters and are thus finalizing a 90 day sample retention period in today's rule. This sample retention requirement also applies to non-VCSB methods which are described below.

For test methods that have not been approved by a VCSB, full test method documentation, including a description of the technology/instrumentation that makes the method functional, as well as subsequent EPA approval of the method is also required. These submissions will also be subject to the Agency's review for 90 days, and the method will be considered approved in the absence of EPA comment. Submission of VCSB methods is not required since they are available in the public domain. In addition, industry and the Agency will likely have had substantial experience with such methods.

As described above, federal government and EPA policy is to use standards developed by voluntary consensus bodies when available. The purpose of the NTTAA, at least in part, is to foster consistency in regulatory requirements, to take advantage of the collective industry wisdom and wide-spread technical evaluation required before a test method is approved by a consensus body, and to take advantage of the ongoing oversight and evaluation of a test method by the consensus body that results from wide-spread use of an approved method *e.g.*, the ongoing round-robin type analysis and typical annual updating of the method by the consensus body. These goals are not met where the Agency allows use of a non-consensus body test method in perpetuity. Moreover, it is not possible to realize many of the advantages that result from consensus status where a test method is used by only one or a few companies. It will not have the practical scrutiny that comes from ongoing wide-spread use, or the independent scrutiny of the consensus body and periodic updating. In addition, EPA does not have the resources to conduct the degree of initial scrutiny or ongoing scrutiny that are practiced by consensus bodies. Nevertheless, EPA believes it is appropriate to allow limited use of a proprietary test method for a limited time, even though the significant advantages of consensus test methods are absent, because EPA can evaluate the initial quality of a method and a company may have invested significant resources in developing a method. However, if after a reasonable time a test method fails to gain consensus body approval, EPA believes approval of the method should be withdrawn because of the absence of ongoing consensus oversight. Accordingly, a non-VCSB method will cease to be qualified five years from the date of its original approval by EPA in the absence of VCSB approval.

To assist the Agency in determining the performance of a given sulfur test method, non-VCSB methods, in particular, we reserve the right to send samples of commercially available fuel to laboratories for evaluation. Such samples are intended for situations in which the Agency has concerns regarding a test method and, in particular, its ability to measure the sulfur content of a random commercially available diesel fuel. Laboratory facilities are required to report their results from tests of this material to the Agency.

iii. What Quality Control Provisions Are Required?

We are requiring ongoing Quality Control (QC) procedures for sulfur measurement instrumentation. These are procedures used by laboratory facilities to ensure that the test methods they have qualified and the instruments on which the methods are run are yielding results with appropriate accuracy and precision, *e.g.*, that the results from a particular instrument do not "drift" over time to yield unacceptable values. It is our understanding that most laboratories already employ QC procedures, and that these are commonly viewed as important good laboratory practices. Laboratories will be required, at a minimum, to abide by the following QC procedures for each instrument used to test batches of diesel fuel under these regulations even where a laboratory elects to use the test method used to establish the precision and accuracy criteria finalized in today's rule:

(1) Follow the mandatory provisions of ASTM D 6299–02, *Standard Practice for Applying Statistical Quality Assurance Techniques to Evaluate Analytical Measurement System Performance*. Laboratories are required to construct control charts from the mandatory QC sample testing prescribed in paragraph 7.1, following the guidelines under A 1.5.1 for individual observation charts and A 1.5.2 for moving range charts.

(2) Follow ASTM D 6299–02 paragraph 7.3.1 (check standards) using

[169] 0.54 and 7.26 are equal to 0.75 times the precision values of 0.72 for 15 ppm sulfur diesel and 9.68 for 500 ppm sulfur diesel, respectively.

a standard reference material. Check standard testing is required to occur at least monthly and should take place following any major change to the laboratory equipment or test procedure. Any deviation from the accepted reference value of the check standard greater than 1.44 ppm for diesel fuel subject to the 15 ppm sulfur standard and 19.36 ppm for diesel fuel subject to the 500 ppm sulfur standard[170] must be investigated.

(3) Upon discovery of any QC testing violation of A 1.5.2.1 or A 1.5.3.2 or check standard deviation greater than 1.44 ppm and 19.36 ppm for 15 ppm sulfur diesel and 500 ppm sulfur diesel, respectively, as provided in item 2 above, any measurement made while the system was out of control must be tagged as suspect and an investigation conducted into the reasons for this anomalous performance. Refiners and importers are required to retain batch samples for 30 days or the period equal to the interval between QC sample tests, whichever is longer. If an instrument is found to be out of control, all of the retained samples since the last time the instrument was shown to be in control must be retested.

(4) QC records, including investigations under item 3 above must be retained for five years and must be provided to the Agency upon request.

b. Requirements To Conduct Fuel Sulfur Testing

Given the importance of assuring that NRLM diesel fuel designated to meet the 15 ppm sulfur standard in fact meets that standard, we are requiring that refiners, importers, and transmix processors test each batch of NRLM diesel fuel designated to meet the 15 ppm sulfur standard and maintain records of such testing. Requiring that refiners, importers, and transmix processors test each batch of fuel subject to the 15 ppm sulfur NRLM standard assures that compliance can be confirmed through testing records, and even more importantly, assures that diesel fuel exceeding the 15 ppm standard is not introduced into commerce as fuel for use in nonroad equipment having sulfur-sensitive emission control devices. Batch testing was not required under the highway diesel fuel rule. Instead, such testing was expected to be performed to establish a defense to potential liability. However, for the same reasons discussed above, today's rule extends this batch testing requirement to15 ppm sulfur highway diesel fuel beginning in 2006.

In order to address situations where refiners produce NRLM diesel fuel using computer-controlled inline blending equipment and do not have storage tanks from which to withdraw samples, we are including in today's final rule a provision to allow refiners to test a composited sample of a batch of diesel fuel for its sulfur content after the diesel fuel has been shipped from the refinery. This inline blending provision is similar to the provision that exists under the reformulated gasoline and gasoline sulfur programs and applies to both highway and NRLM diesel fuel under today's action.

Today's rule does not require downstream parties to conduct every-batch testing. However, we believe that most downstream parties will voluntarily conduct "periodic" sampling and testing for quality assurance purposes if they want to establish a defense to presumptive liability, as discussed in section V.H. below.

2. Two Part-Per-Million Downstream Sulfur Measurement Adjustment

We believe that it is appropriate to recognize sulfur test variability in determining compliance with the 15 ppm sulfur NRLM diesel fuel standards downstream of a refinery or import facility. Thus, today's rule provides that for all 15 ppm sulfur NRLM diesel fuel at locations downstream of a refinery or import facility, sulfur test results can be adjusted by subtracting two ppm. In the same manner as finalized for 15 ppm sulfur highway diesel fuel, the sole purpose of this downstream compliance provision is to address test variability concerns (*see* the highway diesel fuel rule). We received comments suggesting that a higher downstream test tolerance is needed based on the current values for test method variability. However, we anticipate that the reproducibility of sulfur test methods is likely to improve to two ppm or even less by the time the 15 ppm sulfur standard for highway diesel fuel is implemented—four years before implementation date of the 15 ppm standard for NRLM diesel fuel. With this provision, we anticipate that refiners will be able to produce diesel fuel with an average sulfur level of approximately 7–8 ppm and some contamination could occur throughout the distribution system, without fear of causing a downstream violation due solely to test variability. As test methods improve in the future, we will reevaluate whether two ppm is the appropriate allowance for purposes of this compliance provision. We also received comments that a test tolerance should be provided in determining compliance with the 500 ppm sulfur standards for NRLM fuel. We believe that such a tolerance is not needed for fuels subject to a 500 ppm sulfur standard because of the flexibility that refiners possess to produce fuel with a sufficiently low sulfur content to accommodate test variability.

3. Sampling Requirements

Today's rule adopts the same sampling methods adopted by the highway diesel rule (66 FR 5002, January 18, 2001). These sampling methods are American Society for Testing and Materials (ASTM) D 4057–95 (manual sampling) and D 4177–95 (automatic sampling from pipelines/in-line blending). The requirement to use these methods becomes effective for NRLM diesel fuel on June 1, 2007. These same methods were also adopted for use in the Tier 2/Gasoline Sulfur rule.[171]

4. Alternative Sampling and Testing Requirements for Importers of Diesel Fuel Who Transport Diesel Fuel by Tanker Truck

We understand that importers who transport diesel fuel into the U.S. by tanker truck are frequently relatively small businesses that could be subject to a substantial burden if they were required to sample and test each batch of NRLM or highway diesel fuel imported by truck, especially where a trucker imports many small loads of diesel fuel. Therefore, today's rule provides that truck importers may comply with an alternative sampling and testing requirement, involving a sampling and testing program of the foreign truck loading terminal, if certain conditions are met. For an importer to be eligible for the alternative sampling and testing requirement, the terminal must conduct sampling and testing of the NRLM or highway diesel fuel immediately after each receipt into its terminal storage tank but before loading product into the importer's tanker truck storage compartments or immediately prior to loading product into the importer's tanker truck if it hasn't tested after each receipt. Moreover, the importer will be required to conduct periodic quality assurance testing of the terminal's diesel fuel, and the importer will be required to assure EPA that we will be allowed to make unannounced

[170] 1.44 ppm is equal to two times the precision value of 0.72 ppm for 15 ppm diesel and 19.36 is equal to two times the precision value of 9.68 ppm for 500 ppm diesel.

[171] 65 FR 6833–34 (Feb. 10, 2000). Today's rule also provides that these methods be used under the RFG and CG rules. *See* 62 FR 37337 *et seq.* (July 11, 1997).

inspections and audits, to sample and test fuel at the foreign terminal facility, to assure that the terminal maintained sampling and testing records, and to submit such records to EPA upon request.

E. Selection of the Marker for Heating Oil

As discussed in section IV.D, to ensure that heating oil is not shifted into the NRLM market, we need a way to distinguish heating oil from high sulfur or 500 ppm sulfur NRLM diesel fuel produced under the small refiner and credit provisions in today's rule. Currently, there is no differentiation today between fuel used for NRLM uses and heating oil. Both are typically produced to the same sulfur specification, and both are required to have the same red dye added prior to distribution from downstream of the terminal. Based on recommendations from refiners, in the NPRM, we concluded that the best approach to differentiate heating oil from NRLM diesel fuel would be to require that a marker be added to heating oil at the refinery gate. Since the proposal we received additional information which allows us to rely upon record-keeping and reporting provisions to differentiate heating oil from NRLM up to the point where it leaves the terminal (see section IV.D). Therefore, today's rule requires that a marker be added to heating oil before it leaves the terminal gate rather than the refinery gate as proposed.[172]

Section IV.D of today's preamble also discusses the need to distinguish 500 ppm sulfur locomotive and marine fuel produced by refiners and imported from 2010–2012 from 500 ppm sulfur nonroad diesel fuel produced during this time frame under the small refiner, credit, and downstream flexibility provisions in today's rule. Without this ability, it would be possible for 500 ppm sulfur LM diesel fuel to be shifted into the nonroad market during this time period outside of the Northeast/Mid-Atlantic Area and Alaska. Therefore, today's rule requires that from June 1, 2010 through May 31, 2012, the same marker added to heating oil must also be added to 500 ppm sulfur LM diesel fuel produced by a refiner or imported for use outside of the Northeast/Mid-Atlantic Area and Alaska before the fuel leaves the terminal. Nonroad diesel fuel meeting a 500 ppm sulfur standard produced under the small refiner or credit provisions, and 500 ppm sulfur NRLM diesel fuel generated under the downstream flexibility provisions in today's rule could be sold into the LM market outside of the Northeast/Mid-Atlantic Area and Alaska. Such 500 ppm sulfur NRLM diesel fuel does not need to be marked. Therefore, both marked and unmarked 500 ppm sulfur diesel fuel could be used in locomotive and marine diesel equipment outside of the Northeast/Mid-Atlantic Area and Alaska from 2010 through 2012.[173]

As discussed in section IV.D., use of the same marker in heating oil and 500 ppm sulfur LM fuel is feasible because the underlying goal is the same, *i.e.*, keeping 500 ppm sulfur diesel fuel produced as heating oil or LM fuel from begin shifted into the nonroad diesel market from 2010 through 2012. We will be able to determine whether heating oil with a sulfur content greater than 500 ppm has been shifted into the LM market downstream of the terminal by testing the sulfur content of LM. 500 ppm fuel initially designated as heating oil can be later shifted into the LM market, since the sulfur standard for LM diesel fuel during this period is 500 ppm.

Terminal operators suggested that we might be able to rely on record-keeping and reporting downstream of the terminal as well as above the terminal level, thereby eliminating any need for a fuel marker. However, we believe such record-keeping and reporting mechanisms would be insufficient to keep heating oil out of the NRLM market and 500 ppm sulfur LM fuel produced by a refiner or imported out of the nonroad market downstream of the terminal under typical circumstances. We can rely on such measures before the fuel leaves the terminal because it is feasible to require all of the facilities in the distribution system to report to EPA on their fuel transfers. As discussed in section IV.D., these electronic reports can be compared by EPA to identify parties responsible for shifting heating oil into the NRLM market from 2007–2014, 500 ppm sulfur LM fuel into the nonroad market from 2010–2012, and heating oil into the LM market beginning 2014. Downstream of the terminal the parties involved in the fuel distribution system become far too numerous for such a system to be implemented and enforced (including jobbers, bulk plant operators, heating oil dealers, retailers, and even end-users with storage tanks such as farmers. Reporting errors for even a small fraction would require too many resources to track down and correct and would eliminate the effectiveness of the system.

Our proposal envisioned that a fuel marker would be required in heating oil from June 1, 2006 through May 31, 2010, and that the same marker would be required in locomotive and marine fuel from June 1, 2010 through May 31, 2014. As a consequence of finalizing the 15 ppm sulfur standard for locomotive and marine fuel in 2012, we no longer need to require that LM diesel fuel be marked after June 1, 2012. The 2010–2012 marking requirement for 500 ppm sulfur LM diesel fuel does not apply to 500 ppm sulfur LM fuel produced by a refiner or imported in the Northeast/Mid-Atlantic Area or in Alaska. There is an ongoing need to require the continued use of the marker in heating oil indefinitely (*see* section IV of today's preamble).

We proposed that beginning June 1, 2007 SY–124 must be added to heating oil in the U.S. at a concentration of 6 milligrams per liter (mg/L). Today's rule adopts this requirement except for heating oil used in the Northeast/Mid-Atlantic Area and Alaska.[174] The chemical composition of SY–124 is as follows: N-ethyl-N-[2-[1-(2-methylpropoxy)ethoxyl]-4-phenylazo]-benzeneamine.[175] This concentration is sufficient to ensure detection of SY–124 in the distribution system, even if diluted by a factor of 50. Any fuel found with a marker concentration of 0.1 milligrams per liter or more will be presumed to be heating oil. Below this level, the prohibition on use in highway, nonroad, locomotive, or marine applications would not apply.

There are a number of other types of dyes and markers. Visible dyes are most common, are inexpensive, and are easily detected. Using a second dye in addition to the red dye required by IRS in all non-highway fuel for segregation of heating oil based on visual identification raises certain challenges. The marker that we require in heating oil and 500 ppm sulfur LM diesel fuel must be different from the red dye currently required by IRS and EPA and not interfere with the identification of red dye in distillate fuels. Invisible

[172] Heating oil sold inside the Northeast/Mid-Atlantic Area adopted under today's rule and Alaska does not need to contain a marker (*see* section IV.D.).

[173] Inside the Northeast/Mid-Atlantic Area, 500 ppm sulfur fuel produced from transmix or segregated interface could be sold into the LM or heating oil markets from 2010–2012, and could only be sold into the heating oil market after 2012. Outside of the Northeast/Mid-Atlantic Area, such fuel could be sold into the NRLM market from 2010–2012, and into the LM market thereafter.

[174] *See* section IV.D of today's preamble for a discussion of the provisions for the Northeast/Mid-Atlantic Area and Alaska.

[175] Opinion on Selection of a Community-wide Mineral Oils Marking System, ("Euromarker"), European Union Scientific Committee for Toxicity, Ecotoxicity and the Environment plenary meeting, September 28, 1999.

markers are beginning to see more use in branded fuels and are somewhat more expensive than visible markers. Such markers are detected either by the addition of a chemical reagent or by their fluorescence when subjected to near-infra-red or ultraviolet light. Some chemical-based detection methods are suitable for use in the field. Others must be conducted in the laboratory due to the complexity of the detection process or concerns regarding the toxicity of the reagents used to reveal the presence of the marker. Near-infra-red and ultra-violet flourescent markers can be easily detected in the field using a small device and after brief training of the operator. There are also more exotic markers available such as those based on immunoassay, and isotopic or molecular enhancement. Such markers typically need to be detected by laboratory analysis.

We selected SY–124, however, for a number of reasons:

(1) There is considerable data and experience with it which indicates there are no significant issues with its use;

(2) It is compatible with the existing red dye;

(3) Test methods exist to quantify its concentration, even if diluted by a factor of 50 to one;

(4) It is reasonably inexpensive; and

(5) It can be produced and provided by a number of sources.

Effective in August 2002, the European Union (EU) enacted the requirement that SY–124 be added at 6 mg/L to diesel fuel that is taxed at a lower rate in all EU member states.[176] Solvent yellow 124 is referred to as the "Euromarker" in the EU. The EU has found this treatment rate to be sufficient for their enforcement purposes while not interfering with the identification of the various different colored dyes required by different EU member states (including the same red dye that is required in the U.S.). Despite its name, SY–124 does not impart a strong color to diesel fuel when used at a concentration of 6 mg/L. Most often it is reportedly nearly invisible in distillate fuel given that the slight yellow color imparted is similar to the natural color of many distillate fuels.[177] In the presence of red dye, SY–124 can impart a slight orange tinge to the fuel. However, it does not interfere with the visual identification of the presence of red dye or the quantification of the concentration of red dye in distillate fuel. Thus, the use of SY–124 at 6 mg/L in diesel fuel would not interfere with the use of the red dye by IRS to identify non-taxed fuels.

Solvent yellow 124 is chemically similar to other additives used in gasoline and diesel fuel, and has been registered by EPA as a fuel additive under 40 CFR part 79. Therefore, we expect that its products of combustion would not have an adverse impact on emission control devices, such as a catalytic converter. Extensive evaluation and testing of SY–124 was conducted by the European Commission. This included combustion testing which showed no detectable difference between the emissions from marked and unmarked fuel. Norway specifically evaluated the use of distillate fuel containing SY–124 for heating purposes and determined that the presence of the Euromarker did not cause an increase in harmful emissions from heating equipment. Based on the European experience with SY–124, we do not expect that there would be concerns regarding the compatibility of SY–124 in the U.S. fuel distribution system or for use in motor vehicle engines and other equipment such as in residential furnaces.

Our evaluation of the process conducted by the EU in selecting SY–124 for use in the EU convinced us that SY–124 was also the most appropriate marker to propose for use in heating oil under today's program. We received a number of comments expressing concern about the use of SY–124 in heating oil. Based on our evaluation of these comments (summarized below and in the S&A), we continue to believe that SY–124 is the most appropriate marker to specify for use in heating oil and 500 ppm sulfur LM diesel fuel under today's rule. Therefore, today's rule requires that beginning June 1, 2007, SY–124 be added to heating oil, and that from June 1, 2010 through May 31, 2012, SY–124 be added to 500 ppm sulfur LM diesel fuel produced by a refiner or imported at a concentration of 6 mg/L before such fuel leaves the terminal except in the Northeast/Mid-Atlantic Area and Alaska.

The concerns regarding the use of SY–124 in heating oil primarily pertained to: the potential impact on jet engines if jet fuel were contaminated with SY–124; the potential health effects of SY–124 when used in fuel for heating purposes, particularly for unvented heaters; the potential cost impact on fuel distributors and transmix processors; and the potential conflict with IRS red dye requirements.

The American Society of Testing and Materials (ASTM), the Coordinating Research Council (CRC), and the Federal Aviation Administration (FAA) requested that we delay finalizing the selection of a specific marker for use in heating oil in today's rule. They requested that selection of a specific marker should be deferred until testing could be conducted regarding the potential impact of SY–124 on jet engines. The Air Transport Association stated that EPA should conduct an extensive study regarding the potential for contamination, determine the levels at which the marker will not pose a risk to jet engines, and seek approval of SY–124 as a jet fuel additive. Other parties including the Department of Defense (DoD) also stated that EPA should refrain from specifying a heating oil marker under today's rule until industry and other potentially affected parties can recommend an appropriate marker. Representatives of the heating oil industry stated that they were concerned that EPA had not conducted an independent review regarding the safety/suitability of SY–124 for use in heating oil.

We met and corresponded with numerous and diverse parties to evaluate the concerns expressed regarding the use of SY–124, and to determine whether it might be more appropriate to specify a different marker for use in heating oil. These parties include IRS, FAA, ASTM, CRC, various marker/dye manufacturers, European distributors of fuels containing the Euromarker, marker suppliers, and members of all segments in the U.S. fuel distribution system.

We believe that concerns related to potential jet fuel contamination have been sufficiently addressed for us to finalize the selection of SY–124 as the required heating oil marker in today's rule.[178] As discussed in section IV.D of today's preamble, changes in the structure of the fuel program finalized in today's rule from that in the proposed program have allowed us to move the point where the marker must be added from the refinery gate to the terminal. The vast majority of concerns regarding the potential for contamination of jet fuel with SY–124 pertained to the shipment of marked fuel by pipeline. All parties were in agreement that nearly all of the potential for marker contamination of jet fuel would disappear if the point of marker addition was moved to the terminal. We

[176] The European Union marker legislation, 2001/574/EC, document C(2001) 1728, was published in the European Council Official Journal, L203 28.072001.

[177] The color of distillate fuel can range from near water white to a dark blackish brown but is most frequently straw colored.

[178] *See* the Summary and Analysis of Comments for a more detailed discussion of our response to concerns about the possible contamination of jet fuel with the marker prescribed for use in heating oil and 500 ppm sulfur LM fuel under today's rule.

spoke with terminal operators, both large and small, who confirmed that they maintain strictly segregated distribution facilities for red dyed fuel and jet fuel because of jet fuel contamination concerns. The same type of segregation practices will apply to the handling of marked heating oil, marked 500 ppm sulfur LM diesel fuel, and jet fuel since the marker will only be present in heating oil and locomotive and marine fuel when red dye is also present. Therefore, these practices will be equally effective in limiting contamination of jet fuel with SY–124. Downstream of the terminal, the only other chance for marker contamination of jet fuel pertains to bulk plant operators and jobbers that handle marked heating oil and jet fuel. For the most part, these parties also currently maintain strict segregation of the facilities used to transport jet fuel and heating oil. The one exception is that small bulk plant operators that supply small airports sometimes use the same tank truck to alternately transport jet fuel and heating oil. In such cases, they flush the tank compartment prior to transporting jet fuel to remove any residual heating oil left behind after the tank is drained. Since few, if any bulk plants handle LM fuel, it is unlikely that the same tank trucks will be used to alternately transport LM fuel and jet fuel. Thus, we expect that there will be even less chance for LM fuel containing the marker to contaminate jet fuel.

Today's rule requires that heating oil and locomotive and marine fuel which contains the marker must also contain visible evidence of red dye. Therefore, the "white bucket" test that distributors currently use to detect red dye contamination of jet fuel can also be relied upon to detect marker contamination of jet fuel. Based on the above discussion, we concluded that the required addition of the marker to heating oil and 500 ppm sulfur locomotive and marine fuel from 2010–2012 would not significantly increase the likelihood of jet fuel contamination, and that when such contamination might occur, it could be readily identified without the need for additional testing. Our finalization of the Northeast/Mid-Atlantic Area in (*see* section IV.D) also minimizes potential concerns regarding the potential that jet fuel may become contaminated with the marker, since no marker is required in this area. Furthermore, there is expected to be little heating oil used outside of the Northeast/Mid-Atlantic Area, the locomotive and marine market outside of the Northeast/Mid-Atlantic Area is limited. We anticipate that the distribution of marked LM diesel fuel will primarily be by segregated pathways, and the duration of the marker requirement for 500 ppm sulfur LM diesel fuel produced by refiners or imported for use outside of the Northeast/Mid-Atlantic Area and Alaska is only two years. On the whole, we actually expect that today's rule will reduce the potential for jet fuel to become contaminated with the azo dyes such as the IRS-required red dye and SY–124 since visual evidence will no longer be required leaving the refinery gate in 500 ppm NRLM fuel beginning June 1, 2007, and will no longer be required in any off-highway diesel fuel beginning June 1, 2010.

This final rule requires addition of the marker at the terminal rather than the refinery gate as proposed. Based on this change, ASTM withdrew its request to delay the finalization of the marker requirements in today's rule. However, ASTM stated that some concern remains regarding jet fuel contamination downstream of the terminal (due to the limited use of the same tank wagons to alternately transport jet fuel and heating oil discussed above). Nevertheless, ASTM related that these concerns need not delay finalization of the marker requirements in this rule. ASTM intends to support a CRC program to evaluate the compatibility of markers with jet fuel. The Federal Aviation Administration is also undertaking an effort to identify fuel markers that would be compatible for use in jet fuel. We commit to a review of the use of SY–124 in the future based on the findings of the CRC and the FAA, experience with the use of SY–124 in Europe, and future input from ASTM or other concerned parties. If alternative markers are identified that do not raise concerns regarding the potential contamination of jet fuel, we will initiate a rulemaking to evaluate the use of one of these markers in place of SY–124.

Since the NPRM, no new information has been provided which indicates that the combustion of SY–124 in heating equipment would result in more harmful emissions than when combusted in engines, or would result in more harmful emissions than combustion of unmarked heating oil. The European experience with the use of SY–124 and the evaluation process it underwent prior to selection by the EU, provides strong support regarding the compatibility of SY–124 in the U.S. fuel distribution system, and for use in motor vehicle engines and other equipment such as in residential furnaces and nonroad, locomotive, and marine engines. We believe that concerns regarding the potential health impacts from the use of SY–124 do not present sufficient cause to delay finalization of the requirement for it's use that is contained in today's rule.

The European Union intends to review the use of SY–124 after December 2005, but may undertake the review earlier if any health and safety or environmental concerns about its use are raised. We intend to keep abreast of such activities and may initiate our own review of the use of SY–124 depending on the European Union's findings, or other relevant information. There will be nearly four years of accumulated field experience with the use of SY–124 in Europe at the time of the review by the EU and nearly 5 years by the implementation of the marker requirement under today's rule. This will provide ample time for any potential unidentified issues with SY–124 to be identified, and for us to choose a different marker if warranted.

Commenters stated that potential health concerns regarding the use of SY–124 might be exacerbated with respect to its use in unvented space heaters. Commenters further stated that there are prohibitions against the dyeing of kerosene (No. 1 diesel) used in such heaters. No information was provided to support these concerns, however, and we have no information to suggest any health concerns exist regarding the use of SY–124 in unvented heaters. Nevertheless, even if there were such concerns, today's rule will not require SY–124 to be used in the fuel used in unvented heaters. Furthermore, today's rule, does not require that SY–124 be added to kerosene. This resolves most of what concern might remain regarding this issue, since kerosene is the predominate fuel used in unvented heaters. However, the DoD stated that No. 2 diesel fuel is sometimes used in its tent heaters and expressed concern regarding the presence of SY–124 in fuel used for this purpose. We understand that to simplify the DoD fuel distribution system, it is DoD policy to use a single fuel called JP–8 for multiple purposes where practicable, including space heating. JP–8 used for such a purpose would not be subject to today's fuel marker requirement. In cases where JP–8 might not be available for space heating, DoD could avoid the use of SY–124 containing fuel by using kerosene in their space heaters.

We believe that the concerns expressed regarding the potential impact on distributors and transmix processors from the presence of SY–124 in heating oil and 500 ppm sulfur LM fuel have been addressed by moving the point of marker addition to the terminal. Terminal operators stated that they desire the flexibility to blend 500 ppm diesel fuel from 15 ppm diesel fuel and heating oil. This practice would have been prevented by the proposed addition of the marker at the refinery gate. Under today's rule, terminal operators will have access to unmarked high sulfur fuel with which to manufacture 500 ppm diesel fuel by blending with 15 ppm diesel fuel.[179]

Transmix processors stated that the presence of a marker in transmix would limit the available markets for their reprocessed distillates. The feed material for transmix processors primarily consists of the interface mixing zone between batches of fuels that abut each other during shipment by pipeline where this mixing zone can not be cut into either of the adjacent products. If marked heating oil and locomotive and marine fuel was shipped by pipeline, the source material for transmix processors fed by pipelines that carry marked fuel could contain SY–124.[180] Transmix processors stated that it would be prohibitively expensive to segregate pipeline-generated transmix containing the marker from that which does not contain the marker prior to processing, and that they could not economically remove the marker during reprocessing. Thus, in cases where the marker would be present in a transmix processor's feed material, they would be limited to marketing their reprocessed distillate fuels into the heating oil market. Since today's final rule requires that the marker be added at the terminal gate (rather than at the refinery gate), the feed material that transmix processors receive from pipelines will not contain the marker. Hence, they will not typically need to process transmix containing the fuel marker prescribed in today's rule, and today's marker requirement is not expected to significantly alter their operations. There is little opportunity for marker contamination of fuels that are not subject to the marker requirements to occur at the terminal and further downstream. In the rare instances where this might occur, the fuel contaminated would likely also be a distillate fuel, and thus could be sold into the heating oil market without need for reprocessing.

We do not expect that the fuel marker requirements will result in the need for additional fuel storage tanks or tank trucks in the distribution system. As discussed in section VI.A of today's preamble, the implementation of the NRLM sulfur standards in today's rule is projected to result in the need for additional storage tanks and tank truck de-manifolding at a limited number of bulk plant facilities. The marker requirement does not add another criteria apart from the sulfur content of the fuel which would force additional product segregation. As discussed above, industry has expressed concern about the use of the same tank trucks to alternately transport heating oil and jet fuel. We do not expect that the addition of marker to heating oil and 500 ppm sulfur LM diesel fuel will exacerbate these concerns. However, depending on the outcome of the aforementioned CRC program, the addition of marker to heating oil may hasten the current trend to avoid the use of tank trucks to alternately transport jet fuel and heating oil. To the extent that this does occur, we do not expect that it would result in substantial additional costs since few tank truck operators currently use the same tank truck compartments to alternately transport heating oil and jet fuel.

Through our discussions with the IRS, we have confirmed that the presence of SY–124 will not interfere with enforcement of their red dye requirement.[181] Although, SY–124 may impart a slight orange tint to red-dyed diesel fuel, this will not complicate the identification of the presence of the IRS red dye. In fact, IRS has determined that the presence of SY–124 may even enhance enforcement of their fuel tax program.[182] However, as identified in the comments, the implementation of today's marker requirement for heating oil arguably may be in conflict with IRS regulations at 26 CFR 48.4082–1(b) which state that no dye other than the IRS-specified red dye must be present in untaxed diesel fuel. IRS is evaluating what actions might be necessary to clarify that the addition of SY–124 to heating oil would not be in violation of IRS regulations.

IRS also related that they are investigating new markers for potential use either to supplement or to replace red dye under their diesel tax program which might be compatible with jet fuel. IRS stated that it might result in a reduced burden on industry if EPA were to adopt one of the markers from the family of markers that they are investigating. Given the changes to our program in today's final rule, the marker provisions will not impose a significant burden. However, if the IRS program were to develop an alternate marker that would be compatible with jet we will initiate a rulemaking to evaluate the use of one of these markers in place of SY–124 (*see* section VIII.H.).

Commenters also expressed concerns regarding the proprietary rights related to the manufacture and use of SY–124, and stated that EPA should adopt a nonproprietary marker if possible. The proprietary rights related to SY–124 expire several months after the implementation of the marker requirements finalized in today's rule. Therefore, we do not expect that the current proprietary rights regarding SY–124 are a significant concern. Commenters also stated that our estimated cost of SY–124 in the NPRM (0.2 cents per gallon of treated fuel) was high compared to other markers that cost hundredths of a cent per gallon. Since the proposal we have obtained more accurate information which indicates that the current cost of bulk quantities of SY–124 is approximately 0.03 cents per gallon of treated fuel (*see* section VI.A.). Based on conversations with various marker manufacturers, this cost is comparable to or less than other fuel markers.

F. Fuel Marker Test Method

As discussed in section V.E above, today's rule requires the use of SY–124 at a concentration of 6mg/L in heating oil beginning in 2007, and in 500 ppm sulfur LM diesel fuel produced by a refiner or importer from 2010 through 2012, except for such fuels that used in the Northeast/Mid-Atlantic Area and Alaska. There is currently no industry standard test procedure to quantify the presence of SY–124 in distillate fuels. The most commonly accepted method is based on the chemical extraction of the SY–124 using hydrocloric acid solution and cycloxane, and the subsequent evaluation of the extract using a visual spectrometer to determine the concentration of the marker.[183] This test is inexpensive and easy to use for field inspections. However, the test involves reagents that require some safety precautions and the small amount of fuel required in the test must be disposed of as hazardous waste. Commenters expressed concerns about

[179] Terminals that manufacture 500 ppm diesel fuel by blending 15 ppm and high sulfur fuel are treated as a refiner under today's rule. They must also comply with all applicable designate and track requirements, anti-downgrading provisions, and the other applicable requirements in today's rule (see section IV.D of today's preamble).

[180] We do not expect that there will be sufficient demand for 500 ppm sulfur LM diesel fuel produced by refiners or importers to justify its shipment by pipeline after 2010.

[181] Phone conversation between Carl Dalton and Rick Stiff, IRS and Jeff Herzog and Paul Machiele, EPA, February 19, 2004.

[182] *ibid.*

[183] Memorandum to the docket entitled "Use of a Visible Spectrometer Based Test Method in Detecting the Presence and Determining the Concentration of Solvent Yellow 124 in Diesel Fuel."

the use of a test procedure which involves a hazardous reagent (hydrochloric acid) and which generates a waste product that must be disposed of as hazardous waste. Nevertheless, we continue to believe that such safety concerns are manageable here in the U.S. just as they are in Europe and that the small amount of waste generated can be handled along with other similar waste generated by the company conducting the test, and that the associated effort and costs will be negligible.

Changes made in today's final rule from the proposal will mean that few parties in industry will need to test for the marker, thereby minimizing concerns about the burden of such testing. Much of the testing for the fuel marker that was envisioned by industry was associated with detecting marker contamination in other fuels. By moving the required point of marker addition downstream to the terminal, today's rule virtually eliminates these concerns. Where such concerns continue to exist, the presence of the red dye will provide a visual means of detecting marker contamination.[184] Therefore, we expect that the instances where parties will need to test for marker contamination will be rare. Also, the Northeast/Mid-Atlantic Area provisions finalized in today's rule will exempt the vast majority of heating oil used in the U.S. from the marker requirement. Based on the above discussion, we believe that the vast majority of testing for the presence of the fuel marker that will be conducted will be that by EPA for enforcement purposes.

Similar to the approach proposed regarding the measurement of fuel sulfur content discussed in section V.H above, we are finalizing a performance-based procedure to measure the concentration of SY–124 in distillate fuel. Section V.H above describes our rationale for finalizing performance-based test procedures. Under the performance-based approach, a given test method can be approved for use in a specific laboratory or for field testing by meeting certain precision and accuracy criteria. Properly selected precision and accuracy values allow multiple methods and multiple commercially available instruments to be approved, thus providing greater flexibility in method and instrument selection while also encouraging the development and use of better methods and instrumentation in the future. For example, we are hopeful that with more time and effort a simpler test can be developed for SY–124 that can avoid the use of reagents and the generation of hazardous waste that is by product of the current commonly accepted method.

Under the performance criteria approach, methods developed by consensus bodies as well as methods not yet approved by a consensus body will qualify for approval provided they meet the specified performance criteria as well as the record-keeping and reporting requirements for quality control purposes. There is no designated marker test method.

1. How Can a Given Marker Test Method Be Approved?

A marker test method can be approved for use under today's program by meeting certain precision and accuracy criteria. Approval will apply on a laboratory/facility-specific basis. If a company chooses to employ more than one laboratory for fuel marker testing purposes, then each laboratory will have to separately seek approval for each method it intends to use. Likewise, if a laboratory chooses to use more than one marker test method, then each method will have to be approved separately. Separate approval will not be necessary for individual operators or laboratory instruments within a given laboratory facility. The method will be approved for use by that laboratory as long as appropriate quality control procedures were followed.

In developing the precision and accuracy criteria for the sulfur test method, EPA drew upon the results of an inter-laboratory study conducted by the American Society for Testing and Materials (ASTM) to support ASTM's standardization of the sulfur test method. Unfortunately, there has not been sufficient time for industry to standardize the test procedure used to measure the concentration of SY–124 in distillate fuels or to conduct an inter-laboratory study regarding the variability of the method. Nevertheless, the European Union has been successful in implementing its marker requirement while relying on the marker test procedures which are currently available, as noted above. We used, the most commonly used marker test procedure to establish the precision and accuracy criteria on which a marker test procedure would be approved under the today's rule.[185]

There has been substantial experience in the use of this reference market test method since the August 2002 effective date of the European Union's marker requirement. However, EPA is aware of only limited summary data on the variability of the reference test method from a manufacturer of the visible spectrometer apparatus used in the testing.[186] The stated resolution of the test method from the materials provided by this equipment manufacturer is 0.1 mg/L, with a repeatability of plus or minus 0.08 mg/L and a reproducibility of plus or minus 0.2 mg/L.[187] Given the lack of more extensive data, we have decided to use these available data as the basis of the precision and accuracy criteria for the marker test procedure under today's rule (as discussed below). EPA may initiate a review of the precision and accuracy criteria finalized in today's rule should additional test data become available.

Using a similar methodology to that employed in deriving the sulfur test procedure precision value results in a precision value for the marker test procedure of 0.043 mg/L (*see* section V.H).[188] However, we are concerned that the use of this precision value, because it is based on very limited data, might preclude the acceptability of test procedures that would be adequate for the intended regulatory use. In addition, the lowest measurement of marker concentration that will have relevance under the regulations is 0.1 mg per liter. Consequently, today's rule requires that the precision of a marker test procedure will need to be less than 0.1 mg/L for it to qualify.

To demonstrate the accuracy of a given test method, a laboratory facility will be required to perform 10 repeat tests, the mean of which can not deviate from the Accepted Reference Value (ARV) of the standard by more than 0.05 mg/L. We believe that this accuracy level is not overly restrictive, while being sufficiently protective considering that the lowest marker level of

[184] Today's rule requires that red dye be present in heating oil which contains the marker.

[185] Memorandum to the docket entitled "Use of a Visible Spectrometer Based Test Method in Detecting the Presence and Determining the Concentration of Solvent Yellow 124 in Diesel Fuel."

[186] Technical Data on Fuel/Dye/Marker & Color Analyzers, as downloaded from the Petroleum Analyzer Company L.P. Web site at *http://www.petroleum-analyzer.com/product/PetroSpec/lit_pspec/DTcolor.pdf*.

[187] Repeatability and reproducibility are terms related to test variability. ASTM defines repeatability as the difference between successive results obtained by the same operator with the same apparatus under constant operating conditions on identical test materials that would, in the long run, in the normal and correct operation of the test method be exceeded only in one case in 20. Reproducibility is defined by ASTM as the difference between two single and independent results obtained by different operators working in different laboratories on identical material that would, in the long run, be exceeded only in one case in twenty.

[188] *See* section V.H of this proposal for a discussion of the methodology used in deriving the proposed precision and accuracy values for the sulfur test method.

regulatory significance would be 0.1 mg/L. Ten tests will be required using each of two different marker standards, one in the range of 0.1 to 1 mg/L and the other in the range of 4 to 10 mg/L of SY–124. Therefore, a minimum of 20 total tests will be required for sufficient demonstration of accuracy for a given marker test method at a given laboratory facility. Finally, any known interferences for a given test method will have to be mitigated. These tests must be performed using commercially available SY–124 standards. Since the European Union's marker requirement will have been in effect for nearly 5 years by the implementation date of today's marker, we believe that such standards will be available by the implementation date for today's rule.

These requirements are not overly burdensome. To the contrary, these requirements are equivalent to what a laboratory would do during the normal start up procedure for a given test method. In addition, we believe the performance based approach finalized in today's rule will allow regulated entities to know that they are measuring fuel marker levels accurately and within reasonable site reproducibility limits.

2. What Information Would Have To Be Reported to the Agency?

As noted above, the European Union's (EU) marker requirement will have been in effect for nearly five years prior to the effective data for the proposed marker requirements and we expect the EU requirement to continue indefinitely. Thus, we anticipate that the European testings standards community will likely have standardized a test procedure to measure the concentration of SY–124 in distillate fuels prior to the implementation of the marker requirement in today's final rule. The United States testing standards community may also enact such a standardized test procedure. To the extent that marker test methods that have already been approved by a voluntary consensus standards body [189] (VCSB), such as the International Standards Organization (ISO) or the American Society for Testing and Materials (ASTM), each laboratory facility would be required to report to the Agency the precision and accuracy results as described above for each method for which it is seeking approval. Such submissions to EPA, as described elsewhere, will be subject to the Agency's review for 30 days, and the method will be considered approved in the absence of EPA comment. Laboratory facilities are required to retain the fuel samples used for precision and accuracy demonstration for 30 days..

For test methods that have not been approved by a VCSB, full test method documentation, including a description of the technology/instrumentation that makes the method functional, as well as subsequent EPA approval of the method is also required. These submissions are subject to the Agency's review for 90 days, and the method will be considered approved in the absence of EPA comment. Submission of VCSB methods is not required since they are available in the public domain. In addition, industry and the Agency will likely have had substantial experience with such methods.

To assist the Agency in determining the performance of a given marker test method (non-VCSB methods, in particular), we reserve the right to send samples of commercially available fuel to laboratories for evaluation. Such samples are intended for situations in which the Agency has concerns regarding a test method and, in particular, its ability to measure the marker content of a random commercially available diesel fuel. Laboratory facilities are required to report the results from tests on this material to the Agency.

G. Requirements for Recordkeeping, Reporting, and PTDs

1. Registration Requirements

As discussed in section IV.D, by December 31, 2005, or six months prior to handling fuels subject to the designation requirements of today's rule, each entity in the fuel distribution system, up through and including the point where fuel is loaded onto trucks for distribution to retailers or wholesale purchaser-consumers, must register each of its facilities with EPA.

An entity's registration must include the following information:

- Corporate name and address
—Contact name, telephone number, and e-mail address
- For each facility operated by the entity:
—Type of facility (*e.g.* refinery, import facility, pipeline, terminal)
—Facility name
—Physical location
—Contact name, telephone number, and e-mail address

2. Applications for Small Refiner Status

An application of a refiner for small refiner status must be submitted to EPA by December 31, 2004 and shall include the following information:

- The name and address of each location at which any employee of the company, including any parent companies, subsidiaries, or joint venture partners [190] worked From January 1, 2002 until January 1, 2003;
- The average number of employees at each location, based on the number of employees for each of the company's pay periods from January 1, 2002 until January 1, 2003;
- The type of business activities carried out at each location; and
- The total crude oil refining capacity of the corporation. We define total capacity as the sum of all individual refinery capacities for multiple-refinery companies, including any and all subsidiaries, and joint venture partners as reported to the Energy Information Administration (EIA) for 2002, or in the case of foreign refiners, a comparable reputable source, such as professional publication or trade journal.[191] Refiners do not need to include crude oil capacity used in 2002 through a lease agreement with another refiner in which it has no ownership interest.

The crude oil capacity information reported to the EIA is presumed to be correct. However, in cases where a company disputes this information, we will allow 60 days after the company submits its application for small refiner status for that company to petition us with detailed data it believes shows that the EIA's data was in error. We will consider this data in making a final determination about the refiner's crude oil capacity.

Finally, applications for small refiner status must also include information on which small refiner option the refiner expects to use at each of its refineries.

3. Applications for Refiner Hardship Relief

As discussed above in section IV.C, a refiner seeking general hardship relief under today's program will apply to EPA and provide several types of financial and technical information, such as internal cash flow data and information on bank loans, bonds, and assets as well as detailed engineering and construction plans and permit status. Applications for general hardship relief are due June 1, 2005.

[189] These are standard-setting organizations, like ASTM, and ISO that have broad representation of all interested stakeholders and make decisions by consensus.

[190] "Subsidiary" here covers entities of which the parent company has 50 percent or greater ownership.

[191] We will evaluate each foreign refiner?s documentation of crude oil capacity on an individual basis.

4. Pre-Compliance Reports for Refiners

We believe that an early general understanding of the refining industry's progress in complying with the requirements in today's rule will be valuable to both the industry and EPA. As with the highway diesel program, we are requiring that each refiner and importer provide annual reports on the progress of compliance and plans for compliance for each of their refineries or import facilities. These pre-compliance reports are due June 1 of each year beginning in 2005 and continuing through 2011, or until the production of 15 ppm sulfur NR and LM diesel fuel commences, whichever is later.

EPA will maintain the confidentiality of information submitted in pre-compliance reports to the full extent authorized by law. We will report generalized summaries of this data following receipt of the pre-compliance reports. We recognize that plans may change for many refiners or importers as the compliance dates approach. Thus, submission of the reports will not impose an obligation to follow through on plans projected in the reports.

Pre-compliance reports can, at the discretion of the refiner/importer, be submitted in conjunction with the annual compliance reports discussed below and/or the pre-compliance and annual compliance reports required under the highway diesel program, as long as all of the information that is required in all reports is clearly provided. Based on experience with the first pre-compliance reports for the highway diesel program, we are clarifying the information request for the pre-compliance reports as shown below. This should provide responses in a more standardized format which will allow for better aggregation of the data, as well as eliminate reporting of unnecessary information.

Pre-compliance reports must include the following information:

- Any changes in the basic corporate or facility information since registration;
- Estimates of the average daily volumes (in gallons) of each sulfur grade of highway and NRLM diesel fuel produced (or imported) at each refinery (or facility). These volume estimates must be provided both for fuel produced from crude oil, as well as any fuel produced from other sources, and must be provided for the periods of June 1, 2010–December 31, 2010, calendar years 2011–13, January 1, 2014–May 31, 2014, and June 1, 2014–December 31, 2014;
- For entities expecting to participate in the credit program, estimates of numbers of credits to be earned and/or used;
- Information on project schedule by known or projected completion date (by quarter) by the stage of the project. For example, following the five project phases described in EPA's June 2002 Highway Diesel Progress Review report (EPA420–R–02–016): (1) Strategic planning, (2) planning and front-end engineering, (3) detailed engineering and permitting, (4) procurement and construction, and (5) commissioning and startup.
- Basic information regarding the selected technology pathway for compliance (*e.g.*, conventional hydrotreating vs other technologies, revamp vs grassroots, etc.);
- Whether capital commitments have been made or are projected to be made; and
- The pre-compliance reports in 2006 and later years must provide an update of the progress in each of these areas.

5. Compliance Reports for Refiners, Importers, and Distributors of Designated Diesel Fuel

a. Designate and Track Reporting Requirements

i. Quarterly Reports

From June 1, 2007 and through September 1, 2010, all entities who are required to maintain records must report the following information by facility to EPA on a quarterly basis:

- The total volume in gallons of each type of designated diesel fuel for which custody was transferred by the entity to any other entity, and the EPA entity and facility identification number(s), as applicable, of the transferee; and
- The total volume in gallons of each type of designated diesel fuel for which custody was received by the entity from any other entity and the EPA entity and facility identification number(s), as applicable, of the transferor.

If a facility receives fuel from another facility that does not have an EPA facility identification number then that batch of fuel must be designated and reported as (1) heating oil if it is marked, (2) highway diesel fuel if taxes have been assessed, (3) NRLM diesel fuel if the fuel is dyed but not marked.

Terminals must also report the results of all compliance calculations including the following:

- The total volumes received of each fuel designation required to be reported over the quarterly compliance period;
- The total volumes transferred of each fuel designation required to be reported over the quarterly compliance period;
- Beginning and ending inventories of each fuel designation required to be reported over the quarterly compliance period;
- Calculations showing that the volume of highway diesel fuel distributed from the facility relative to the volume received did not increase since June 1, 2007; and
- Calculations showing that the volume of high sulfur NRLM diesel fuel did not increase by a greater proportion than the volume of heating oil over the quarterly compliance period (not applicable in the Northeast/Mid-Atlantic Area or Alaska).

The quarterly compliance periods and dates by which the reports are due for each period are as follows.

TABLE V.G–1. QUARTERLY COMPLIANCE PERIODS AND REPORTING DATES [a]

Quarterly compliance period	Report due date
July 1 through September 30.	November 30.
October 1 though December 31.	February 28.
January 1 through March 31.	May 31.
April 1 through June 30	August 31.

Notes: [a] The first quarterly reporting period will be from June 1, 2007 though September 30, 2007 and the last quarterly compliance period will be from April 1, 2010 through May 31, 2010.

ii. Annual Reports

Beginning June 1, 2007, all entities that are required to maintain records for batches of fuel must report by facility on an annual basis (due August 31) information on the total volumes received of each fuel designation as well as the results of all compliance calculations including the following:

- The total volumes transferred of each fuel designation;
- Beginning and ending inventories of each fuel designation;
- In Alaska, for diesel fuel designated as high sulfur NRLM delivered from June 1, 2007 through May 31, 2010 and for diesel fuel designated as 500 ppm sulfur NRLM delivered from June 1, 2010 through May 31, 2014, refiners must report all information required under their individual compliance plan, including the end-users to whom each batch of fuel was delivered and the total delivered to each end-user for the compliance period;
- Ending with the report due August 31, 2010, calculations showing that the volume of highway diesel fuel distributed from the facility relative to the volume received did not increase since June 1, 2007;

• Ending with the report due August 31, 2010, calculations showing that the volume of highway diesel fuel distributed from the facility relative to new volume received did not increase over the annual compliance period by more than two percent of the total volume of highway diesel fuel received;

• Ending with the report due August 31, 2010, calculations showing that the volume of high sulfur NRLM diesel fuel did not increase by a greater proportion than the volume of heating oil over the annual compliance period (not applicable in the Northeast/Mid-Atlantic Area or Alaska);

• Calculations showing that the volume of heating oil did not decrease over the annual compliance period, beginning June 1, 2010 (not applicable in the Northeast/Mid-Atlantic Area or Alaska); and

• From June 1, 2010 through August 1, 2012, calculations showing that the volume of 500 ppm sulfur NR diesel fuel did not increase by a greater proportion than the volume of 500 ppm sulfur LM diesel fuel over the annual compliance period (not applicable in the Northeast/Mid-Atlantic Area and Alaska.

b. Other Reporting Requirements

After the NRLM diesel fuel sulfur requirements begin on June 1, 2007, refiners and importers will be required to submit annual compliance reports for each refinery or import facility. If a refiner produces 15 ppm sulfur or 500 ppm sulfur fuel early under the credit provisions, its annual compliance reporting requirement will begin on June 1 following the beginning of the early fuel production. These reporting requirements will sunset after all flexibility provisions end (*i.e.*, after May 31, 2014). Annual compliance reports will be due on August 31.

A refiner's or importer's annual compliance report must include the following information for each of its facilities:

• Batch reports for each batch produced or imported providing information regarding volume, designation (*e.g.*, 500 highway), sulfur level and whether the fuel was dyed and/or marked. Each batch can only have one designation. Therefore, if a refiner ships 100 gallons of 500 ppm sulfur fuel in 2007 and wants to designate 50 gallons as highway 500 and 50 gallons as NR 500, the refiner must report two separate batches and there must be two PTDs—one for 50 gallons of highway 500 and one for 50 gallons of NR 500).

• Report on the generation, use, transfer and retirement of diesel sulfur credits. Credit transfer information must include the identification of the number of credits obtained from, or transferred to, each entity. Reports must also show the credit balance at the start of the period, and the balance at the end of the period. NRLM or nonroad diesel sulfur credit information is required to be stated separately from highway diesel credit information since the two credit programs are treated separately.

• For a small refiner that elects to produce 15 ppm sulfur NRLM diesel fuel by June 1, 2006 and therefore is eligible for a limited relaxation in its interim small refiner gasoline sulfur standards, the annual reports must also include specific information on gasoline sulfur levels and progress toward highway and NRLM diesel fuel desulfurization.

6. PTDs

Refiners, importers, and other parties in the distribution system must provide information on commercial PTDs that identify diesel fuel distributed by use designation and sulfur content; *i.e.*, for use in or motor vehicles, nonroad equipment, locomotive and marine equipment, or nonroad, locomotive, and marine diesel equipment, as appropriate, and the sulfur standard to which the fuel is subject. The PTD must indicate whether the fuel is diesel fuel, heating oil, kerosene, exempt fuel, or other. It must further state whether it is No. 1 or No. 2, dyed or undyed, marked heating oil, marked LM fuel, or unmarked. The specific designations on PTDs will change during the course of the program. For example, the highway designation for 500 ppm sulfur fuel ends after 2010. Where a party delivers or receives a particular load of fuel that has a uniform sulfur content but that has two different designations, the parties must utilize two different PTDs. For example, if, in 2007 a refiner moves 1,000 gallons of 500 ppm sulfur diesel into a pipeline, and the refiner's designation is that half of that product is highway 500 and half is nonroad 500, the parties would utilize one PTD for 500 gallons of highway 500 ppm sulfur diesel fuel and another for 500 gallons of nonroad 500 diesel fuel.

As in other fuels programs, PTDs must accompany each transfer of either title or custody of fuel. However, only custody transfers are relevant to compliance with the designation and tracking requirements and the downgrade limitations, and transfers to retail outlets and wholesale purchaser-consumers of fuel by distributors below the truck rack are not covered by the designate and track scheme. Therefore, the PTDs for these non-designate and track transfers are somewhat more straightforward.

We believe this additional information on commercial PTDs is necessary to maintain the integrity of the various grades of diesel fuel in the distribution system. Parties in the system will be better able to identify which type of fuel they are dealing with and more effectively ensure that they are meeting the requirements of today's program. This in turn will help to ensure that misfueling of sulfur sensitive engines does not occur and that the program results in the needed emission reductions.

Today's rule allows the use of product codes to convey the required information, except for transfers to truck carriers, retailers and wholesale purchaser-consumers. We believe that more explicit language on PTDs to these parties is necessary since employees of such parties are less likely to be aware of the meaning of product codes. PTDs will not be required for transfers of product into nonroad, locomotive, or marine equipment at retail outlets or wholesale purchaser-consumer facilities with the exception of mobile refuelers. Mobile refuellers are required to provide a separate PTD to their customers for each type of fuel (*e.g.*, 500 ppm sulfur NRLM diesel fuel, 15 ppm sulfur NRLM diesel fuel, or 15 ppm highway diesel fuel) that they dispense from tanker trucks or other vessels into motor vehicles, nonroad diesel engines or nonroad diesel engine equipment, for each instance when they refuel such equipment at a given location.[192]

a. Kerosene and Other Distillates To Reduce Viscosity

To ensure that downstream parties can determine the sulfur level of kerosene or other distillates that may be distributed for use for blending into 15 ppm sulfur highway or NRLM diesel fuel, for example, to reduce viscosity in cold weather, we are requiring that PTDs identify distillates specifically distributed for such use as meeting the 15 ppm sulfur standard.

b. Exported Fuel

Consistent with other EPA fuel programs, NRLM diesel fuel exported from the U.S. is not required to meet the sulfur standards of today's regulations. For example, where a refiner designates a batch of diesel fuel for export, and can demonstrate through commercial documents that the fuel was exported, such fuel would not be required to

[192] Only one PTD is required for each fuel designation or classification regardless of the number of motor vehicles or the number of diesel-powered NRLM equipment that are fueled.

comply with the NRLM sulfur standards in today's rule. Product transfer documents accompanying the transfer of custody of the fuel at each point in the distribution system are required to state that the fuel is for export only and may not be used in the United States.

c. Additives

Today's rule requires that PTDs for additives for use in NRLM diesel fuel state whether the additive complies with the 15 ppm sulfur standard. Like the highway diesel rule, this program allows the sale of additives, for use by fuel terminals or other parties in the diesel fuel distribution system, that have a sulfur content greater than 15 ppm under specified conditions.

For additives that have a sulfur content less than 15 ppm, the PTD must state: "The sulfur content of this additive does not exceed 15 ppm." For additives that have a sulfur content greater than 15 ppm, the additive manufacturer's PTD, and PTDs accompanying all subsequent transfers, must provide a warning that the additive's sulfur content exceeds 15 ppm; the maximum sulfur content of the additive; the maximum recommended concentration for use of the additive in diesel fuel (stated as gallon of additive per gallon of diesel fuel); and the increase in sulfur concentration of the fuel the additive will cause when used at the maximum recommended concentration.

Today's rule contains provisions for aftermarket additives sold to owner/operators for use in diesel powered nonroad equipment. These provisions are in response to concerns that additives designed for engines not requiring 15 ppm sulfur fuel, such as locomotive or marine engines, could accidentally be introduced into nonroad engines if they had no label stating appropriate use. Beginning June 1, 2010, aftermarket additives for use in nonroad equipment must be accompanied by information that states that the additive complies with the 15 ppm sulfur standard. We believe this information is necessary for end users to determine if an additive is appropriate for use.

7. Recordkeeping Requirements for Refiners and Importers

Refiners and importers of distillate fuel must maintain the following designate and track records for the distillate fuel they produce and/or import. The specific types of distillate fuel that are subject to these recordkeeping requirements are described below for the various periods of the program.[193]

- Batch number (including whether it is an incoming or out-going batch for refineries that also handle previously designated fuel);
- Batch designation;
- Volume in gallons;
- Date/time of day of custody transfer; and
- Name and EPA entity and facility identification number of the facility to which the batch was transferred.

For highway diesel fuel, the records must also identify whether the batch was received or delivered with or without taxes assessed. For NRLM diesel fuel, the records must also identify whether the batch was received or delivered with or without the IRS red dye. For heating oil, the records must indicate whether the batch was received or delivered with or without the fuel marker. From June 1, 2010, through May 31, 2012, the records for LM fuel batches must also indicate whether the batch was received or delivered with or without the fuel marker.

In addition to the designate and track records, refiners and importers must maintain the following records on the highway and NRLM diesel fuel that they produce and/or import:

- PTDs;
- Sampling and testing results for sulfur content (for highway and NRLM diesel fuel that is subject to either the 15 ppm or 500 ppm sulfur standards), as well as sampling and testing results that are part of a quality assurance program;
- Sampling and testing results for the cetane index or aromatics content, as well as sampling and testing results for additives;
- Records on credit generation, use, transfer, purchase, or termination, maintained separately for the highway and NRLM diesel fuel credit programs; and
- Records related to individual compliance plans, if applicable, and annual compliance calculations.

a. June 1, 2006 through May 31, 2007

Refiners and importers must maintain the records listed above for each batch of diesel fuel that they designate and transfer custody of during the time period from June 1, 2006 through May 31, 2007, with the following fuel types:

- No. 1 15 ppm sulfur highway diesel fuel;
- No. 2 15 ppm sulfur highway diesel fuel;
- 15 ppm sulfur NRLM diesel fuel;
- No. 1 500 ppm sulfur highway diesel fuel;
- No. 2 500 ppm sulfur highway diesel fuel; or
- 500 ppm sulfur NRLM diesel fuel.

b. June 1, 2007 Through May 31, 2010

Refiners and importers must maintain the records listed above for each batch of distillate fuel that they designate and transfer custody of during the time period from June 1, 2007 through May 31, 2010 with the following fuel types:

- No. 1 15 ppm sulfur highway diesel fuel;
- No. 2 15 ppm sulfur highway diesel fuel;
- 15 ppm sulfur NRLM diesel fuel;
- No. 1 500 ppm sulfur highway diesel fuel;
- No. 2 500 ppm sulfur highway diesel fuel; or
- 500 ppm sulfur NRLM diesel fuel;
- High sulfur NRLM diesel fuel; or
- Heating oil.

c. June 1, 2010 Through May 31, 2012

Refiners and importers must maintain the records listed above for each batch of diesel fuel that they designate and transfer custody of during the time period from June 1, 2010 through May 31, 2012, with the following fuel types:

- 500 ppm sulfur NR diesel fuel;
- 500 ppm sulfur LM diesel fuel; or
- Heating oil.

d. June 1, 2012 Through May 31, 2014

Refiners and importers must maintain the records listed above for each batch of distillate fuel that they transfer custody of and designate during the time period from June 1, 2012 through May 31, 2014 with the following fuel types:

- 15 ppm sulfur highway or NRLM diesel fuel;
- 500 ppm sulfur NRLM diesel fuel; or
- Heating oil.

d. June 1, 2014 and Beyond

Refiners and importers must maintain the records listed above for each batch of heating oil that they transfer custody of and designate during the time period from June 1, 2014 and beyond.

8. Recordkeeping Requirements for Distributors

Distributors of distillate fuel must maintain the following designate and track records on a facility-specific basis for the distillate fuel they distribute. The specific distillate fuel designations that are subject to these recordkeeping requirements are described below for the various periods of the program.

[193] Transmix processors and terminal operators acting as refiners that produce 500 ppm sulfur diesel fuel for sale into the locomotive and marine markets are also subject to the recordkeeping requirements.

- Batch number (including whether it is an incoming or out-going batch);
- Batch designation;
- Volume in gallons;
- Date/time of day of custody transfer;
- Name and EPA entity and facility identification number of the facility from which the fuel batch was received or to which the fuel batch was delivered;
- Beginning and ending inventory volumes on a quarterly basis; and
- Inventory adjustments.

For highway diesel fuel, the records must also identify whether the batch was received or delivered with or without taxes assessed. For NRLM diesel fuel, the records must also identify whether the batch was received or delivered with or without the IRS red dye. For heating oil, the records must indicate whether the batch was received or delivered with or without the fuel marker. From June 1, 2010, through October 1, 2012, the records must indicate whether LM fuel was received or delivered with or without the fuel marker.[194] In addition to these designate and track records, distributors will be required to maintain records related to their quarterly and annual compliance calculations as well as copies of all PTDs.

If a facility receives fuel from another facility that does not have an EPA facility identification number then that batch of fuel must be designated as (1) heating oil if it is marked, or from 2010 through 2012, LM diesel fuel if the fuel is dyed and marked and is not heating oil (2) highway diesel fuel if taxes have been assessed, and (3) NRLM diesel fuel if the fuel is dyed but not marked.

If a facility delivers fuel to other facilities and that fuel is either 500 ppm sulfur highway diesel fuel on which taxes have been assessed or 500 ppm sulfur NRLM, or LM diesel fuel into which red dye has been added pursuant to IRS requirements, then the facility does not need to maintain separate records for each of the other facilities to which it delivered fuel. Similarly, if a facility delivers batches of marked heating oil to other facilities, then it does not need to maintain separate records for each of the other facilities to which it delivered the marked heating oil. If a facility only receives marked heating oil (*i.e.*, it does not receive any unmarked heating oil), then it does not need to maintain any heating oil records. Similarly, if a facility only receives highway diesel fuel on which taxes have been assessed or NRLM diesel fuel which has been dyed pursuant to IRS regulations (*i.e.*, it does not receive any untaxed highway diesel fuel or undyed NRLM diesel fuel), then it does not need to maintain records of the 500 ppm sulfur highway or NRLM diesel fuel that it receives.

a. June 1, 2006 Through May 31, 2007

Facilities that receive No. 2 15 ppm sulfur highway diesel fuel and distribute any No. 2 500 ppm sulfur highway diesel fuel, must maintain records for each batch of diesel fuel with the following designations that they receive or deliver during the time period from June 1, 2006 through May 31, 2007:

- No. 1 15 ppm sulfur highway diesel fuel;
- No. 2 15 ppm sulfur highway diesel fuel;
- No. 2 500 ppm sulfur highway diesel fuel; and
- 500 ppm sulfur NRLM diesel fuel.

b. June 1, 2007 Through May 31, 2010

All facilities must maintain records for each batch of diesel fuel or heating oil with the following designations for which they receive or transfer custody during the time period from June 1, 2007 through May 31, 2010:

- No. 1 15 ppm sulfur highway diesel fuel;
- No. 2 15 ppm sulfur highway diesel fuel;
- No. 1 500 ppm sulfur highway diesel fuel;
- No. 2 500 ppm sulfur highway diesel fuel;
- 500 ppm sulfur NRLM diesel fuel;
- 15 ppm sulfur NRLM diesel fuel;
- High sulfur NRLM diesel fuel; and
- Heating oil.

c. June 1, 2010 Through May 31, 2012

All facilities must maintain records for each batch of diesel fuel or heating oil with the following designations for which they receive or transfer custody during the time period from June 1, 2007 through May 31, 2012. This requirement does not apply to facilities located in the Northeast/Mid-Atlantic Area or Alaska.

- 500 ppm sulfur NR diesel fuel;
- 500 ppm sulfur LM diesel fuel; or
- Heating oil.

d. June 1, 2012 Through May 31, 2014

Facilities that receive unmarked fuel designated as heating oil, must maintain records for each batch of diesel fuel with the following designations that they receive or deliver during the time period from June 1, 2012 through May 31, 2014. This requirement does not apply to facilities located in Alaska or the Northeast/Mid-Atlantic Area unless they deliver marked heating oil to facilities outside of these areas.

- 500 ppm sulfur NRLM diesel fuel; and
- Heating oil.

9. Recordkeeping Requirements for End-Users

Today's program also contains certain recordkeeping provisions for end-users. From June 1, 2007 through October 1, 2010, end-users that receive any batch of high sulfur NRLM in Alaska must maintain records of each batch of fuel received for use in NRLM equipment unless otherwise allowed by EPA. From June 1, 2010 through October 1, 2012, end-users that receive any batch of 500 ppm sulfur NR in Alaska must maintain records of each batch of fuel received for use in NR equipment unless otherwise allowed by EPA. In addition, from June 1, 2012 through October 1, 2014, end-users that receive any batch of 500 ppm sulfur NRLM in Alaska must maintain records of each batch of fuel received for use in NRLM equipment unless otherwise allowed by EPA.

10. Record Retention

We are adopting a retention period of five years for all records required to be kept under today's rule. This is the same period of time required in other fuels rules, and it coincides with the applicable statute of limitations. We believe that most parties in the distribution system would maintain some or all of these records for this length of time even without the requirement.

This retention period applies to PTDs, records required under the designate and track provisions, records of any test results performed by any regulated party for quality assurance purposes or otherwise (whether or not such testing was required by this rule), along with supporting documentation such as date of sampling and testing, batch number, tank number, and volume of product. Business records regarding actions taken in response to any violations discovered must also be maintained for five years.

All records that are required to be maintained by refiners or importers participating in the generation or use of credits, hardship options (or by importers of diesel fuel produced by a foreign refiner approved for the temporary compliance option or a hardship option), including small refiner options, are also covered by the retention period.

[194] After August 1, 2012, LM fuel distributed from terminals must contain a concentration of the marker no greater than 0.1 mg/L. After October 1, 2012, LM fuel at any location in the fuel distribution system must contain no more than a trace amount of the marker (0.1 mg/L).

H. Liability and Penalty Provisions for Noncompliance

1. General

The liability and penalty provisions of the today's NRLM diesel sulfur rule are very similar to the liability and penalty provisions found in the highway diesel sulfur rule, the gasoline sulfur rule, the reformulated gasoline rule and other EPA fuels regulations.[195] Regulated parties are subject to prohibitions which are typical in EPA fuels regulations, such as prohibitions on selling or distributing fuel that does not comply with the applicable standard, and causing others to commit prohibited acts. For example, liability will also arise under the NRLM diesel rule for violating certain prohibited acts and requirements, such as: Distributing or dispensing NR diesel fuel not meeting the 15 ppm sulfur standard for use in model year 2011 or later nonroad equipment (and after Dec 1, 2014 into any nonroad diesel equipment); distributing or dispensing diesel fuel not meeting the 500 ppm sulfur standard for locomotive and marine engines; distributing fuel containing the marker for use in engines that require the use of fuel that does not contain the marker; prohibitions and requirements under the designate and track provisions in today's rule, including specific prohibitions and requirements regarding fuel produced or distributed in the Northeast/Mid-Atlantic Area or in Alaska.[196]

Small refiners and refiners using credits can produce high sulfur NRLM when NRLM would otherwise be required to meet a 500 ppm sulfur standard, and can produce 500 ppm sulfur NR or LM diesel fuel when nonroad or LM diesel fuel would otherwise be required to meet a 15 ppm sulfur standard. A refiner that produces fuel under the small refiner and credit provisions would be in violation unless they can demonstrate that they meet the definition of a small refiner or have sufficient credits for the volume of fuel produced. All regulated parties will be liable for a failure to meet certain requirements, such as the record-keeping, reporting, or PTD requirements, or causing others to fail to meet such requirements.

Under today's rule, the party in the diesel fuel distribution system that controls the facility where a violation occurred, and other parties in that fuel distribution system (such as the refiner, reseller, and distributor), will be presumed to be liable for the violation.[197] As in the Tier 2 gasoline sulfur rule and the highway diesel fuel rule, today's rule explicitly prohibits causing another person to commit a prohibited act or causing non-conforming diesel fuel to be in the distribution system. Non-conforming fuels include: (1) Diesel fuel with sulfur content above 15 ppm incorrectly represented as appropriate for model year 2011 or later nonroad equipment or other engines requiring 15 ppm fuel; (2) diesel fuel with sulfur content above 500 ppm incorrectly represented as appropriate for nonroad equipment or locomotives or marine engines after the applicable date for the 500 ppm sulfur standard for these pieces of equipment; (3) heating oil that is required to contain the marker which does not, LM fuel which is required to contain the marker which does not, or other fuels that are required to be free of the marker in which the marker is present; (4) fuel designated or labeled as 500 ppm sulfur highway diesel fuel above and beyond the volume balance limitations; (5) fuel designated or labeled as NRLM above and beyond the volume balance limitations; or (6) fuels otherwise not complying with the requirements of this rule. Parties outside the diesel fuel distribution system, such as diesel additive manufacturers and distributors, are also subject to liability for those diesel rule violations which could have been caused by their conduct.

Today's rule also provides affirmative defenses for each party presumed liable for a violation, and all presumptions of liability are rebuttable. In general, in order to rebut the presumption of liability, parties will be required to establish that: (1) The party did not cause the violation; (2) PTD(s) exist which establish that the fuel or diesel additive was in compliance while under the party's control; and (3) the party conducted a quality assurance sampling and testing program. As part of their affirmative defense diesel fuel refiners or importers, diesel fuel additive manufacturers, and blenders of high sulfur additives into diesel fuel, will also be required to provide test results establishing the conformity of the product prior to leaving that party's control. Blenders of static dissipater additives have alternative defense provisions as discussed in section V.C. Branded refiners have additional affirmative defense elements to establish. The defenses under the nonroad diesel sulfur rule are similar to those available to parties for violations of the highway diesel sulfur, reformulated gasoline, gasoline volatility, and the gasoline sulfur regulations. Today's rule also clarifies that parent corporations are liable for violations of subsidiaries, in a manner consistent with the gasoline sulfur rule and the highway diesel sulfur rule. Finally, the NRLM diesel sulfur rule mirrors the gasoline sulfur rule and the highway diesel sulfur rule by clarifying that each partner to a joint venture will be jointly and severally liable for the violations at the joint venture facility or by the joint venture operation.

As is the case with the other EPA fuels regulations, today's rule will apply the provisions of section 211(d)(1) of the Clean Air Act (Act) for the collection of penalties. These penalty provisions currently subject any person that violates any requirement or prohibition of the diesel sulfur rule to a civil penalty of up to $32,500 for every day of each such violation and the amount of economic benefit or savings resulting from the violation.[198] A violation of a NRLM diesel sulfur standard will constitute a separate day of violation for each day the diesel fuel giving rise to the violation remains in the fuel distribution system. Under today's regulation, the length of time the diesel fuel in question remains in the distribution system is deemed to be twenty-five days unless there is evidence that the fuel remained in its distribution system a lesser or greater amount of time. This is the same time presumption that is incorporated in the

[195] *See* section 80.5 (penalties for fuels violations); section 80.23 (liability for lead violations); section 80.28 (liability for gasoline volatility violations); section 80.30 (liability for highway diesel violations); section 80.79 (liability for violation of RFG prohibited acts); section 80.80 (penalties for RFG/CG violations); section 80.395 (liability for gasoline sulfur violations); section 80.405 (penalties for gasoline sulfur regulations).; and section 80.610–614 (prohibited acts, liability for violations, and penalties for highway diesel sulfur regulations.

[196] Today's rule, in 40 CFR 80.610, provides that no person shall, inter alia, "dispense, supply, offer for supply, store or transport * * *" fuel not in compliance with applicable standards and requirements starting on a certain date. These prohibitions apply at downstream locations such as retail outlets, wholesale purchaser-consumer facilities as well as end-user locations. The act of storage or transport refers to storage or transport in fuel storage tanks from which fuel is dispensed into motor vehicles or NRLM engines or equipment. It does not refer to storing or transporting the fuel that is in the motor vehicle propulsion tank or other tank that is incorporated in the NRLM equipment for the purpose of supplying the engine with fuel. While the prohibition against dispensing inappropriate fuels does apply as of the applicable date, the motor vehicle or NRLM engine or equipment may continue to burn any fuel in the motor vehicle fuel tank or NRLM equipment fuel tank that was properly dispensed into such tank.

[197] An additional type of liability, vicarious liability, is also imposed on branded refiners under today's rule.

[198] This limit is amended periodically pursuant to Congressional authority to change maximum civil penalties to account for inflation.

RFG, gasoline sulfur and highway diesel sulfur rules. The penalty provisions in today rule are also be similar to the penalty provisions for violations of these regulations.

EPA has included in today's rule two prohibitions for "causing" violations: (1) Causing another to commit a violation; and (2) causing non-complying diesel fuel to be in the distribution system. These causation prohibitions are like similar prohibitions included in the gasoline sulfur and the highway diesel sulfur regulations, and, as discussed in the preamble to those rules, EPA believes they are consistent with EPA's implementation of prior motor vehicle fuel regulations. *See* the liability discussion in the preamble to the gasoline sulfur final rule, at 65 FR 6812 *et seq.*

The prohibition against causing another to commit a violation will apply where one party's violation is caused by the actions of another party. For example, EPA may conduct an inspection of a terminal and discover that the terminal is offering for sale nonroad diesel fuel designated as complying with the 15 ppm sulfur standard, while the fuel, in fact, had an actual sulfur content greater than the standard.[199] In this scenario, parties in the fuel distribution system, as well as parties in the distribution system of any diesel additive that had been blended into the fuel, will be presumed liable for causing the terminal to be in violation. Each party will have the right to present an affirmative defense to rebut this presumption.

The prohibition against causing non-compliant diesel fuel to be in the distribution system will apply, for example, if a refiner transfers non-compliant diesel fuel to a pipeline. This prohibition could encompass situations where evidence shows high sulfur diesel fuel was transferred from an upstream party in the distribution system, but EPA may not have test results to establish that parties downstream also violated a prohibited act with this fuel.

The Agency expects to enforce the liability scheme of the NRLM diesel sulfur rule in the same manner that we have enforced the similar liability schemes in our prior fuels regulations. As in other fuels programs, we will attempt to identify the party most responsible for causing the violation, recognizing that party should primarily be liable for penalties for the violation.

[199] At downstream locations the violation will occur if EPA's test result show a sulfur content of greater than 17 ppm, which takes into account the two ppm adjustment factor for testing reproducibility for downstream parties.

2. What are the Liability Provisions for Additive Manufacturers and Distributors, and Parties That Blend Additives into Diesel Fuel?

a. General

The final highway diesel rule permits the blending of diesel fuel additives with sulfur content in excess of 15 ppm into 15 ppm highway diesel fuel under limited circumstances. As more fully discussed earlier in this preamble, this rule also permits downstream parties to blend fuel additives having a sulfur content exceeding 15 ppm into 15 ppm nonroad diesel, provided that: (1) The blending of the additive does not cause the diesel fuel's sulfur content to exceed the 15 ppm sulfur standard; (2) the additive is added in an amount no greater than one volume percent of the blended product; and (3) the downstream party obtained from its additive supplier a product transfer document ("PTD") with the additive's sulfur content and the recommended treatment rate, and that it complied with such treatment rate. As discussed in section V.C, today's rule includes alternate affirmative defense requirements for blenders of S–D additives that can contribute a maximum of 0.050 ppm to the sulfur content of finished fuel subject to the 15 ppm sulfur standard. Today's rule also implements these same alternate defense requirements regarding the blending of such additives into 15 ppm highway diesel fuel.

Since today's rule permits the limited use in nonroad diesel fuel of additives with high sulfur content, the Agency believes it might be more likely that a diesel fuel sulfur violation could be caused by the use of high sulfur additives. This could result from the additive manufacturer's misrepresentation or inaccurate statement of the additive's sulfur content or recommended treat rate on the additive's PTD, or an additive distributor's contamination of low sulfur additives with high sulfur additives during transportation. The increased probability that parties in the diesel additive distribution system could cause a violation of the sulfur standard warrants the imposition by the Agency of increased liability for such parties. Therefore, today's rule, like the final highway diesel rule, explicitly makes parties in the diesel additive distribution system liable for the sale of nonconforming diesel fuel additives, even if such additives have not yet been blended into diesel fuel. In addition, today's rule imposes presumptive liability on parties in the additive distribution system if diesel fuel into which the additive has been blended is determined to have a sulfur level in excess of its permitted concentration. This presumptive liability will differ depending on whether the blended additive was designated as meeting the 15 ppm sulfur standard (a "15 ppm additive") or designated as a greater than 15 ppm sulfur additive (a "high sulfur additive"), as discussed below.

b. Liability When the Additive Is Designated as Complying with the 15 ppm Sulfur Standard

Additives blended into diesel fuel downstream of the refinery are required to have a sulfur content no greater than 15 ppm, and be accompanied by PTD(s) accurately identifying them as complying with the 15 ppm sulfur standard, with the sole exception of diesel additives blended into nonroad diesel fuel at a concentration no greater than one percent by volume of the blended fuel.

All parties in the fuel and additive distribution systems will be subject to presumptive liability if the blended fuel exceeds the sulfur standard. The two ppm downstream adjustment will apply when EPA tests the fuel subject to the 15 ppm sulfur standard. Low sulfur additives present a less significant threat to diesel fuel sulfur compliance than would occur with the use of additives designated as possibly exceeding 15 ppm sulfur. Thus, parties in the additive distribution system of the low sulfur additive could rebut the presumption of liability by showing the following: (1) Additive distributors will only be required to produce PTDs stating that the additive complies with the 15 ppm sulfur standard; (2) additive manufacturers are also be required to produce PTDs accurately indicating compliance with the regulatory requirements, as well as producing test results, or retained samples on which tests could be run, establishing the additive's compliance with the 15 ppm sulfur standard prior to leaving the manufacturer's control. Once they meet their defense to presumptive liability, these additive system parties will only be held responsible for the diesel fuel non-conformity in situations in which EPA can establish that the party actually caused the violation.

Under today's rule, parties in the diesel fuel distribution system will have the typical affirmative defenses of other fuels rules. For parties blending an additive into their diesel fuel, the requirement to maintain PTDs showing that the product complied with the regulatory standards will necessarily include PTDs for the additive that was used, affirming the compliance of the additive and the fuel.

c. Liability When the Additive Is Designated as Having a Possible Sulfur Content Greater than 15 ppm

Under today's rule, a nonroad diesel fuel additive will be permitted to have a maximum sulfur content above 15 ppm if the blended fuel continues to meet the 15 ppm standard and the additive is used at a concentration no greater than one volume percent of the blended fuel. However, if nonroad diesel fuel containing that additive is found by EPA to have high sulfur content, then all the parties in both the additive and the fuel distribution chains will be presumed liable for causing the nonroad diesel fuel violation.

Since this type of high sulfur additive presents a much greater probability of causing diesel fuel non-compliance, parties in the additive's distribution system will have to satisfy an additional element to establish an affirmative defense. In addition to the elements of an affirmative defense described above, parties in the additive distribution system for such a high sulfur additive will also be required to establish that they did not cause the violation, an element of an affirmative defense that is typically required in EPA fuel programs to rebut presumptive liability.

Parties in the diesel fuel distribution system will essentially have to establish the same affirmative elements as in other fuels rules, with an addition comparable to the highway diesel rule. Blenders of high sulfur additives into 15 ppm sulfur nonroad diesel fuel, will have to establish a more rigorous quality control program than will exist without the addition of such a high sulfur additive. For additives other than static dissipater additives, to establish a defense to presumptive liability, the Agency has adopted the proposal to require test results establishing that the blended fuel was in compliance with the 15 ppm sulfur standard after being blended with the high sulfur additive. This additional defense element will be required as a safeguard to ensure nonroad diesel fuel compliance, since the blender has voluntarily chosen to use an additive which increases the risk of diesel fuel non-compliance.

An exception to this defense element is made for blenders of static dissipater additives, that are allowed by today's rule to contribute no more than 0.05 ppm to the sulfur content of a finished fuel subject to the 15 ppm sulfur standard. As discussed in section V.C.5, blenders of such additives may rely on volume accounting reconciliation records in lieu of the requirement to sample and test each batch of fuel subject to the 15 ppm sulfur standard after the addition of an additive that exceeds the 15 ppm sulfur standard. Today's rule also implements these same alternate defense requirements regarding the blending of such additives into 15 ppm highway diesel fuel.

I. How Will Compliance With the Sulfur Standards Be Determined?

Today's rule provides that compliance with the sulfur standards and use requirements under today's rule can be determined by evaluating the designate and track records (discussed in section IV.D.) and other records, such as PTDs; by evaluating compliance with the fuel marker requirements discussed in section IV.D and V.E; and by sampling fuel and testing for sulfur content. Today's rule includes a requirement for refiners and importers to measure the sulfur content of every batch of NRLM fuel designated under the rule, using a testing methodology approved under the provisions discussed in section V.H of this preamble. In general, downstream parties must conduct only periodic sampling and testing as an element of a defense to presumptive liability (retailers are exempt from sampling and testing). Today's rule further provides that in determining compliance, any evidence from any source or location can be used to establish the diesel fuel sulfur level, provided that such evidence is relevant to whether the sulfur level would have met the applicable standard had compliance been determined using an approved test methodology. While the use of a non-approved test method might produce results relevant to determining sulfur content, this does not remove any liability for failing to conduct required batch testing using an approved test method. This is consistent with the approach taken under the gasoline sulfur rule and the highway diesel sulfur rule.

For example, the Agency might not have sulfur results derived from an approved test method for diesel fuel sold by a terminal, yet the terminal's own test results, based on testing using methods other than those approved under the regulations, could reliably show a violation of the sulfur standard. Under today's rule, evidence from the non-approved test method could be used to establish the diesel fuel's sulfur level that would have resulted if an approved test method had been conducted. This type of evidence is available for use by either the EPA or the regulated party, and could be used to show either compliance or noncompliance. Similarly, absent the existence of sulfur test results using an approved method, commercial documents asserting the sulfur level of diesel fuel or additive could be used as some evidence of what the sulfur level of the fuel would be if the product would have been tested using an approved method.

The Agency believes that the same statutory authority for EPA to adopt the gasoline sulfur rule's evidentiary provisions, Clean Air Act section 211(c), provides appropriate authority for the evidentiary provisions of today's diesel sulfur rule. For a fuller explanation of this statutory authority, see the gasoline sulfur final rule preamble, 65 FR 6815, February 10, 2000.

VI. Program Costs and Benefits

In this section, we present the projected cost impacts and cost effectiveness of the nonroad Tier 4 emission standards and fuel sulfur requirements. We also present a benefit-cost analysis and an economic impact analysis. The benefit-cost analysis explores the net yearly economic benefits to society of the reduction in mobile source emissions likely to be achieved by this rulemaking. The economic impact analysis explores how the costs of the rule will likely be shared across the manufacturers and users of the engines, equipment and fuel that would be affected by the standards.

We revised our cost and benefit analysis to reflect the comments we received on our analysis. The fuel-related costs have been updated to reflect information received from refiners as part of EPA's highway diesel fuel program, comments received on the nonroad NPRM, as well as more recent information available on future energy costs and the cost of advanced desulfurization technologies. The engine and equipment-related costs were revised to reflect additional R&D costs associated with tailoring R&D to each particular engine line and to accommodate changes in the final emission control requirements, particularly with regard to engines above 750 hp. These costs are also now presented in 2002 instead of 2001 dollars. With regard to the benefits analysis, we have updated our methods consistent with Science Advisory Board (SAB) advice as specified in RIA chapter 9. Finally, we adjusted the economic impact analysis to reflect the revised cost inputs and to explicitly model the impacts on the locomotive and marine intermediate market sectors.

The results detailed below show that this rule would be highly beneficial to society, with net present value benefits through 2036 of $805 billion using a 3 percent discount rate and $352 billion using a 7 percent discount rate, compared to a net present value of social cost of about $27 billion using a 3 percent discount rate and $14 billion using a 7 percent discount rate. The impact of these costs on society should be minimal, with the prices of goods and services produced using equipment and fuel affected by standards being expected to increase about 0.1 percent.

Further information on these and other aspects of the economic impacts of this emission control program are summarized in the following sections and are presented in more detail in the Final RIA for this rulemaking.

A. Refining and Distribution Costs

Meeting the 500 and 15 ppm sulfur caps will generally require that refiners add hydrotreating equipment and possibly new or expanded hydrogen and sulfur plants in their refineries. We have estimated the cost of building and operating this equipment using the same basic methodology which was described in the NPRM. We have updated that analysis with new information obtained from the vendors of advanced desulfurization technology, to better reflect current crude oil properties and refinery configurations, as well as future hydrogen costs. We have also incorporated information received from refiners regarding their plans to produce 15 ppm highway diesel fuel from 2006–2010. Finally, we incorporated the 15 ppm cap on locomotive and marine fuel in 2012, as well as improving our analysis of the impact of this cap on costs incurred in the distribution system.

The costs to provide NRLM fuel under the two-step fuel program are summarized in Table VI.A–1 below. All of the following costs estimates are in 2002 dollars. Capital investments have been amortized at 7 percent per annum before taxes. These estimates do not include costs associated with fuel sulfur testing, labeling, reporting or record keeping, which we believe will be small relative to those associated with refining, distribution and lubricity additives. A more detailed description of the costs associated with this final rule is presented in the Final RIA.

TABLE VI.A–1.—COST OF PROVIDING NRLM DIESEL FUEL

(cents per gallon of affected fuel)

NRLM diesel fuel	Years	Affected fuel volume (million gallons per year) [a]	Refining	Distribution (and lubricity)	Total
500 ppm	2007–2010	11,860	1.9	0.2	2.1
	2010–2012	3,589	2.7	0.6	3.3
	2012–2014	715	2.9	0.6	3.5
15 ppm	2010–2012	8,145	5.0	0.8	5.8
	2012–2014	12,068	5.6	0.8	6.4
	2014 +	13,399	5.8	1.2	7.0

Notes: [a] Volumes shown are for first full year in each period (2008, 2011, 2013, and 2015).

The costs shown (and all of the costs described in the rest of this section) apply to the 74 percent of current NRLM fuel that currently contains more than 500 ppm sulfur (hereafter referred to as the affected volume).

In 2014, the affected volume of NRLM fuel is 14.6 billion gallons out of total NRLM fuel volume of 19.7 billion gallons. The other 5.1 billion gallons of NRLM fuel is currently spillover from fuel certified to the highway diesel fuel standards. We expect this to continue under the 2007 highway diesel fuel program. Thus, 26 percent of NRLM fuel will already meet at least a 500 ppm sulfur cap by 2007 and a 15 ppm cap by 2010 and will not be affected by today's rule. The costs and benefits of desulfurizing this highway fuel which spills over into the non-highway markets was included in our cost estimates for the 2007 highway diesel fuel rule.

The estimated cost of the first step of the NRLM fuel program is slightly less than that projected in the NPRM (cents per gallon). However, we have increased our estimated cost of the second step significantly in response to comments. These comments and the changes to our cost estimates are discussed in more detail in the next two sections. The combined cost for both steps is therefore somewhat higher than expected in the NPRM, but nevertheless consistent with projections for the cost of 15 ppm highway diesel fuel.

We expect that the increased cost of refining and distributing 500 ppm NRLM fuel will be completely offset by reductions in maintenance costs, while those for 15 ppm NRLM fuel will be significantly offset. These savings will apply to all diesel engines in the fleet due to the reduced fuel sulfur content, not just new engines. Refer to section V.B for a more complete discussion on the projected maintenance savings associated with lower sulfur fuels.

1. Refining Costs

Methodology: We followed the same process that we used in the NPRM to project refining costs, though we have broken down the description into five steps instead of four.

First, we estimate the total volume of NRLM fuel which must be desulfurized during each step of the program, as well as each refinery's future total production of distillate fuel. Current and future demand for all distillate fuels except diesel fuel for land-based equipment were based on estimates from the Energy Information Administration's (EIA) Fuel Oil and Kerosene Survey (FOKS) for 2001 and the 2003 Annual Energy Outlook (AEO). EPA's NONROAD emission model was used to estimate both current and future fuel consumption by land-based nonroad equipment to ensure the consistent treatment of both the costs and benefits associated with this rule. Table VI.A–2 shows our projections of the volumes of fuel affected by today's rule. These volumes exclude NRLM fuel expected to be certified to highway diesel fuel sulfur caps prior to the implementation of this rule. They also exclude distillate fuel meeting a 500 ppm cap which is produced during distribution from highway diesel fuel, jet fuel, etc.

TABLE VI.A–2.—VOLUME OF NRLM FUEL AFFECTED BY TODAY'S RULE
(billion gallons per year)

	Nonroad		Locomotive and marine		Total	
	500 ppm	15 ppm	500 ppm	15 ppm	500 ppm	15 ppm
2008	8,406	0	3,454	0	11,860	0
2011	614	8,145	2,975	0	3,589	8,145
2013	468	8,671	247	3,395	715	12,066
2015	0	10,539		2,860	0	13,399

This marks a change from the proposal, where all distillate fuel volumes were based on EIA FOKS and AEO estimates. Commenters pointed out that this approach underestimated fuel-related costs relative to emission reductions and monetized benefits, since the NONROAD fuel volumes used to estimate the latter were larger. We in fact had acknowledged this inconsistency in the proposal and had said we would address it in the final rule. Our approach to address the inconsistency was to utilize the land-based nonroad fuel volumes estimated by the NONROAD model for both the costs and monetized benefits. However, we also conducted a sensitivity analysis whereby both emissions and costs were estimated using EIA estimates of fuel demand by land-based nonroad equipment. The results of that analysis are discussed in chapter VII of the Final RIA.

We made one other revision to the volume of diesel fuel affected by this rule. In analyzing the impact of the 2007 highway diesel fuel program for the NPRM analysis, we estimated that 4.4 percent of 15 ppm highway diesel fuel would be contaminated during shipment and not available for sale as 15 ppm highway fuel. This increased the volume of 15 ppm highway fuel which had to be produced at refineries before accounting for the production of additional 500 and 15 ppm NRLM fuel in response to the NRLM fuel program. Due to comments made on the NRPM (discussed in section VI.A.3. below), we have improved our analysis to track the disposition of this contaminated 15 ppm fuel. Much of this contaminated fuel can be sold as 500 ppm NRLM from 2007–2014 and as L&M fuel thereafter. Thus, the contaminated 15 ppm fuel reduces the volume of 500 and 15 ppm NRLM fuel which must be produced at refineries.

Second, total distillate production by individual refineries were based on their actual production volumes in 2002, as reported to EIA. This represents a minor revision to the NPRM analysis, which utilized actual refiner production in 2000. The number of refineries needing to produce 500 ppm and 15 ppm diesel fuel under today's final rule was based on the projected diesel fuel and heating oil demand in 2014.[200] To be consistent, the 2002 distillate production volumes of individual refiners were increased to 2014 levels using EPA projections of growth in total distillate production by domestic refiners.

Third, we estimated the cost to desulfurize diesel fuel to both 500 ppm and 15 ppm for each domestic refinery. This considered both the volume of diesel fuel being produced and its composition (*e.g.*, percentage of straight run, light cycle oil, etc.). Estimates of the volumes of diesel fuel already being desulfurized to meet the highway diesel fuel standards in 2006–2010 prior to the implementation of this final rule were based on refiners' pre-compliance reports.[201] This marks a change from the NPRM analysis, where we assumed that refiners would continue to produce their current mix of highway and high sulfur diesel fuel. While many refiners indicated that their plans were preliminary and subject to change, we consider these projections to be more probable than assuming that current producers of diesel fuel will make no change to their product mix in complying with the highway rule. Meeting the 15 ppm highway diesel fuel cap will require significant investment, but some refiners will face more than others. Some refiners will be able to revamp their current hydrotreater, while others will need to build an entirely new unit. Some refiners will be able to expand their production of highway fuel at little incremental cost, while others will be able to reduce their investment substantially by reducing their production volume. Use of refiners' own projections, as opposed to our own cost methodology assumptions, allows us to incorporate as much refinery-specific information as is currently possible.

In projecting desulfurization costs, we updated a number of the inputs to our cost estimation methodology. We increased natural gas and utility costs to reflect those projected in EIA's 2003 AEO. The NPRM analysis utilized projections from 2002 AEO. Forecasted natural gas costs in 2003 AEO are considerable higher than in 2002 AEO, though still lower than current market prices. In response to comments, we also increased the factor for off-site capital costs to better reflect the cost of sulfur plant expansions. The NPRM analysis utilized an off-site factor developed in support of the Tier 2 gasoline and 2007 highway diesel fuel programs, where the amount of sulfur removed per gallon was a fraction of that occurring here with NRLM fuel. We also continued to update our cost estimates for advanced desulfurization technologies, as these technologies continue their evolution. As discussed in Section IV, the latest information concerning Process Dynamics's IsoTherming process indicate somewhat higher costs than earlier estimates. We also reduced our projection of the penetration of these advanced technologies in 2010 from 80 to 60 percent.

Fourth, we estimated which refineries will likely find it difficult to stay in the heating oil market after the implementation of the NRLM sulfur standards, due to their location relative to major pipelines and the size of the heating oil market in their area. Those not located in major heating oil markets and not connected to pipelines serving these areas were projected to have to

[200] The year 2014 represents a mid-point between the initial year of today's fuel program and the end of the expected life of desulfurization equipment (roughly 15 years).

[201] Under EPA's 2007 highway diesel program, refiners are required to submit their production plans for highway diesel fuel for 2006–2010. The first of these reports were due during the summer of 2003. EPA published a summary of the results this past fall. We consider these reports to provide a more accurate projection of individual refinery plans than our projections made during the highway fuel FRM. The latter was based on cost minimization using our refinery-specific desulfurization refinery model.

meet the 500 and 15 ppm caps in 2007 and 2010, respectively.

Fifth, we estimated which of the remaining refineries would likely produce NLRM fuel under today's program. As was done in the proposal, we assumed that those refineries with the lowest projected compliance costs would be the most likely to produce the required fuel until demand was met. Inter-PADD transfers of fuel between PADD 3 and PADD 1 were not constrained. PADD 3 refineries were also assumed to supply PADD 2 with 15 ppm NRLM fuel once all PADD 2 refineries were producing 15 ppm distillate fuel. We also assumed that domestic refineries would preferentially supply the lowest sulfur fuels compared to imports. Thus, imports of 15 and 500 ppm NRLM fuel were only assumed after all refineries in a PADD were projected to produce either 15 or 500 ppm fuel, respectively. The small refiner provisions included in today's NRLM fuel program were considered, as these provisions temporarily reduce the volume of 500 and 15 ppm fuel required to be produced in 2007 and 2010, respectively. This portion of the methodology was the same as that used in the NRPM analysis.

Results: Based on EIA data, in 2002 114 refineries produced highway diesel fuel and 102 refineries produce high sulfur diesel fuel or heating oil. Based on refiners' pre-compliance reports, we project that 100 refineries will produce 15 ppm highway diesel fuel; 96 refineries starting in 2006 and 4 in 2010. Of these 100 refineries, 96 currently produce some volume of highway diesel fuel, while 4 refineries currently only produce high sulfur distillate fuel. Also, 18 refineries will cease to produce highway diesel fuel and shift to producing solely high sulfur distillate fuel. This will leave a total of 92 refineries still producing high sulfur distillate after full implementation of the 2007 highway diesel fuel program.

The number of these 92 domestic refineries expected to produce either 15 or 500 ppm NRLM diesel fuel in response to today's rule is summarized in Table VI.A–3.

TABLE VI.A–3.—REFINERIES PROJECTED TO PRODUCE NRLM DIESEL FUEL UNDER THIS FINAL RULE

Year of program	500 ppm NRLM diesel fuel		15 ppm NRLM diesel fuel	
	All refineries	Small refineries	All refineries	Small refineries
2007–2010	36	0	0	0
2010–2012	26	13	32	2
2012–2014	15	13	47	2
2014+	0	0	63	15

During the four periods shown in table VI.A–3, two roughly parallel sets of standards become effective. For non-small refiners, the 500 ppm NRLM fuel cap starts in 2007, followed by the 15 ppm nonroad fuel cap in 2010, in turn followed by the 15 ppm L&M fuel cap in 2012. For small refiners, the 500 ppm NRLM fuel cap starts in 2010, followed by the 15 ppm nonroad NRLM fuel cap in 2014. As shown, beginning in 2014, 63 refineries are projected to be affected by today's final rule. After complete implementation of today's rule, 29 refineries are expected to be able to produce high sulfur heating oil, some as their entire distillate production, others along with 15 ppm fuel. The number of refineries estimated to be affected by today's rule is one more than that projected in the NPRM. There, we estimated that 62 refineries would have to produce either 15 or 500 ppm NRLM fuel in 2014 and beyond.

We project that the capital cost involved to meet the 2007 500 ppm sulfur cap will be $310 million. This represents about $10 million for each of the 30 refineries building a new hydrotreater. Six refineries are expected to produce 500 ppm NRLM fuel using existing hydrotreaters no longer being used to produce 500 ppm highway fuel. The total investment cost is roughly half that projected in the NPRM ($600 million). The decrease is due to a greater volume of 500 ppm NRLM fuel coming from existing hydrotreaters. This conclusion is based on the number of refineries leaving the highway diesel fuel market according to the refiners' highway program pre-compliance reports. The investment per refinery that we projected in the NPRM ($9.7 million) was essentially unchanged. Operating costs will be about $4.9 million per year for the average refinery, or slightly greater than that projected in the NPRM (due to higher hydrogen costs and a lower percentage of hydrocrackate in the NRLM pool). The average cost of producing 500 ppm NRLM fuel in 2007 will be 1.9 cents per gallon, 0.3 cent per gallon lower than that projected in the NPRM, due primarily to the reduced capital expenditure.

In 2010, an additional $1170 million will be invested in revamped and new desulfurization equipment, $1090 million to meet the 15 ppm nonroad fuel cap and $80 million to produce 500 ppm NRLM fuel no longer eligible for a small refiner exemption to sell high sulfur NRLM fuel. In 2012, an additional $590 million will be invested in revamped and new desulfurization equipment to meet the 15 ppm L&M cap Finally, in 2014 an additional $210 million will be invested in additional 15 ppm fuel capacity. Thus, total capital cost of new equipment and revamps related to the NRLM fuel program will be $2280 million, or $36 million per refinery, roughly 5 percent greater than that projected in the NPRM. Total operating costs will be about $8.1 million per year for the average refinery, slightly lower than that projected in the NPRM ($8.3 million per year). The total refining cost, including the amortized cost of capital, will be 5.0, 5.6 and 5.8 cents per gallon of new 15 ppm NRLM fuel in 2010, 2012, and 2014, respectively.

The 500 pm NRLM fuel being produced in 2010 is projected to cost 2.7 cents per gallon. The cost of this 500 ppm fuel is higher than that projected in the NPRM, due primarily to a higher cost for natural gas in the future. The 500 pm, small refiner fuel being produced in 2012 is projected to cost 2.9 cents per gallon. All of these costs are relative to the cost of producing high sulfur fuel today, and includes the cost of meeting the 500 ppm standard beginning in 2007.

The 15 ppm refining costs are significantly higher than the 4.4 cent per gallon cost projected in the NPRM for the option where L&M fuel was controlled to 15 ppm in addition to nonroad fuel. The increase is due to the changes in refining cost methodology described above, particularly the reduced use of advanced desulfurization technology, reduced synergies with the highway fuel program and increased natural gas costs.

The average refining costs by refining region are shown in table VI.A–4 below. These costs include consideration of the small refiner provisions. Combined costs are shown for PADDs 1 and 3 because of the large volume of diesel fuel which is shipped from PADD 3 to PADD 1.

TABLE VI.A–4.—AVERAGE REFINING COSTS BY REGION

[Cents per gallon]

	500 ppm Cap			15 ppm Cap		
	2007–2010	2010–2012	2012–2014	2010–2012	2012–2014	2014+
PADDs 1 & 3	1.6	3.7	2.5	4.6	4.9	5.1
PADD 2	2.8	2.9	3.7	7.1	7.8	7.8
PADD 4	3.3	9.0	9.0	11.6	11.7	11.8
PADD 5	1.2	2.8	3.5	4.3	4.3	5.7
Nationwide	1.8	2.7	2.9	5.0	5.6	5.8

Fuel-Only Control Programs: We used the same methodology to estimate refining costs for stand-alone 500 ppm and 15 ppm NRLM fuel programs. The fully phased in refining impacts of a 15 ppm NRLM standard are the same as those described above for the final rule in 2014 and beyond. A fully phased in 500 ppm NRLM fuel program is projected to affect 63 refineries, cost 2.0 cents per gallon and require a capital investment of $480 million.

2. Distribution Costs

Today's rule is projected to impact distribution costs in four ways. First, we project that a slightly greater volume of diesel fuel will have to be distributed, due to the fact that some of the desulfurization processes reduce the fuel's volumetric energy density during processing. Total energy is not lost during processing, as the total volume of fuel is increased in the hydrotreater. However, a greater volume of fuel must be consumed in the engine to produce the same amount of power. We project that desulfurizing diesel fuel to 500 ppm will reduce volumetric energy content by 0.7 percent. The cost of which is equivalent to 0.08 cent per gallon of affected NRLM fuel.[202] We project that desulfurizing diesel fuel to 15 ppm will reduce volumetric energy content by an additional 0.52 percent. This will increase the cost of distributing fuel by an additional 0.05 cents per gallon, for a total cost of 0.13 cents per gallon of affected 15 ppm NRLM fuel.

The second impact on distribution costs relates to the disposition of 15 ppm fuel contaminated during pipeline shipment. We received comments that the control of L&M fuel sulfur content, particularly to 15 ppm, would make it difficult to sell off-specification 15 ppm fuel. The comments argued that much of this material would have to be shipped back to refineries and reprocessed to meet the 15 ppm cap. We designed the program finalized today to allow the continued sale of 500 ppm fuel into the NRLM market until June 1, 2014, and into the locomotive and marine market indefinitely. By doing so, we were able to minimize, though not eliminate, much of the reprocessing and distribution cost impacts of concern. We have evaluated both the production and potential sale of distillate interface and estimated the distribution cost impacts of today's final rule provisions. The details of this analysis are contained in chapter 7 of the Final RIA.

In our analysis of the 15 ppm highway fuel program, we projected that the need to protect the quality of 15 ppm highway diesel fuel would increase the volume of highway diesel fuel downgraded to a lower value product, such as high sulfur diesel fuel and heating oil, from its current level of approximately 2.2 percent to 4.4 percent. Under today's rule, we expect that 15 ppm NRLM fuel will be shipped together with 15 ppm highway. Thus, the size of each batch of 15 ppm fuel will increase, but the number of batches will not. As the downgrade occurs at the interface between batches, the volume being downgraded should not increase. At the same time, we are not projecting that interface volume will decrease, as high sulfur fuels, such as jet fuel and, in some cases heating oil, will still be in the system.

The issue here is the market to which this interface volume can be sold. When this interface volume meets the specifications of one of the two fuels being shipped next to each other, the interface is simply added to the batch of that fuel. For example, the interface between regular and premium gasoline is added to the regular grade batch. Or, the interface between jet fuel and heating oil is added to the heating oil batch. One interface which is never added to either adjacent batch is a mixture of gasoline and any distillate fuel, such as jet or diesel fuel. If this interface was added to the distillate batch, the gasoline content in the interface would result in a violation of the distillate's flash point specification. If this interface was added to the gasoline batch, it would cause the gasoline to violate its end point specification. Therefore, this interface must be shipped to a transmix processor to separate the mixture into naphtha (a sub-octane gasoline) and distillate. The 2007 highway diesel fuel program will not change this practice. The naphtha produced by transmix processors from gasoline/distillate mixtures is usually blended with premium gasoline to produce regular grade gasoline. The distillate produced is an acceptable high sulfur diesel fuel or heating oil, though if the feed material was primarily low sulfur distillate and gasoline it will likely also meet the current 500 ppm highway fuel cap.

With the implementation of the highway diesel rule, there is another incompatible interface, that between jet fuel and 15 ppm diesel fuel. This interface can not be cut into jet fuel due to end point and other concerns. However, it can usually be cut into 500 ppm diesel fuel as long as the sulfur level of the jet fuel is not too high. With the lowering of the highway standard to 15 ppm, however, this will no longer be possible. We expect that pipelines minimize this interface by abutting jet fuel and high sulfur distillate in the pipeline whenever possible. However, it will be unavoidable under many circumstances. A substantial part of the pipeline distribution system currently does not handle high sulfur distillate, and we expect that the highway program and today's rule will likely cause additional pipeline systems to discontinue carrying high sulfur distillate. Pipelines that do not carry high sulfur distillates will generate this

[202] *See* chapter 7 of the RIA for further details regarding our estimation of distribution costs.

interface whenever they ship jet fuel.[203] The highway rule, and today's rule projects that pipeline operators will segregate this interface by cutting it into a separate storage tank. Because this interface can be sold as 500 ppm NRLM fuel or heating oil, and because these markets exist nationwide, there is little impact beyond the need for refiners to produce more 15 ppm highway diesel fuel (compared to the volume of highway diesel fuel produced prior to the implementation of the 15 ppm standard), which was considered as part of the refining costs in the highway diesel rule.

With control of nonroad fuel to 15 ppm sulfur in 2010 and LM fuel to 15 ppm sulfur in 2012, the opportunities to downgrade interface to another product become increasing limited. Where limited this will increase costs due to the need to transport the interface to where it can be marketed or to a facility for reprocessing. In areas with large heating oil markets, such as the Northeast and the Gulf Coast, the control of NRLM sulfur content will still have little impact on the sale of this interface. However, in areas lacking a large heating oil market, the sale of this distillate interface will be more restricted. Because this interface will composed of 15 ppm diesel fuel and jet fuel, we estimate that the distillate interface created should nearly always meet a 500 ppm cap.[204] Thus, this interface can be added to 500 ppm NRLM batches (as well as heating oil, where it is present at the terminal) through 2014. After 2014, this 500 ppm interface fuel can only be sold as L&M fuel or heating oil. An exception to this applies in the Northeast/Mid-Atlantic Area, where this interface cannot be sold into the nonroad fuel market after 2010, nor into the L&M fuel market after 2012.

In chapter 7 of the Final RIA, we estimate the costs related to handling this interface fuel during the four time periods (2007–2010, 2010–2012, 2012–2014, and 2014 and beyond). We project that there will be no additional costs prior to 2010, as 500 ppm fuel will be the primary NRLM fuel and be widely distributed. Beyond 2010, we estimate that terminals will have to add a small storage tank for this fuel, as 500 ppm highway diesel fuel and the majority of 500 ppm NRLM disappears from the distribution system. In many places, this interface will be the primary, if not sole source of 500 ppm fuel, so existing tankage to add this interface to will be limited. We have also added shipping costs to transport this fuel to NRLM and heating oil users. The volume of this interface is significant, sometimes a sizeable percentage of the combined NRLM fuel and heating oil markets. In the post-2014 period, the volume of this interface fuel is larger than the combined L&M fuel and heating oil markets in certain PADDs. Also, the volume of interface received at each terminal will vary substantially, depending on where that terminal is on the pipeline. The advantage of this is that where the interface accumulates it may be of sufficient volume to justify marketing as a separate grade of fuel. Conversely, the potential users of this 500 ppm interface fuel may not be located near the terminals with the fuel necessitating additional transportation costs.

Prior to 2014, 500 ppm fuel can be used as NRLM fuel and heating oil outside of the Northeast/Mid-Atlantic Area. Additional storage tanks will be needed in some cases, as this will be the only source of 500 ppm fuel in the marketplace. Amortizing the cost of a range of storage tank sizes over 15 years of weekly shipments at a seven percent rate of return before taxes costs produced an amortized cost of 0.2–1.6 cents per gallon. These costs include the carrying cost of the fuel stored in the tank. We estimate that the average storage cost will be closer to the lower end of this range, or 0.5 cent per gallon. Nonroad fuel users are fairly ubiquitous. Thus, increased shipping distances should be fairly short. We estimated 45 miles at a cost of roughly 1.5 cents per gallon. The distance to L&M fuel users will likely be longer, roughly 100 miles, but cost the same due to greater efficiencies of rail transport. It will likely cost more to deliver interface fuel to heating oil users, as many of these users are smaller, not evenly dispersed geographically, purchase fuel seasonally, and lack rail connections. We estimate that transport distances will increase an average of 85 miles and cost an additional 3.0 cents per gallon over today's costs to deliver this fuel to the end user, in addition to the 0.5 cent per gallon storage cost. When spread over all the 15 and 500 ppm NRLM fuel being produced from 2010–2014 due to today's rule, the additional distribution cost from 2010–2014 is 0.4 cents per gallon.

Starting in 2014, this interface fuel can no longer be sold to the nonroad fuel market. Since the interface volume does not change, this increases the volume of fuel that must be sold to the L&M and heating oil markets. Thus, overall, transportation distances and costs will likely increase. We expect that the transportation cost for fuel sold to the L&M market will increase from 1.5 to 3.0 cents per gallon, while that for heating oil will increase to 5.0 cents per gallon, both including fuel storage. However, in PADD 5, the volume of interface generated exceeds the total fuel demand of these two markets. Thus, we estimate that some fuel will have to be shipped back to refineries and reprocessed to meet a 15 ppm cap and shipped out a second time. We estimate that the cost of this shipping and reprocessing will cost 10 cents per gallon. When spread over all the 15 ppm NRLM fuel being produced after 2014 due to today's rule, the additional distribution cost is 0.8 cent per gallon.

The third impact of today's rule on distribution costs is related to the need for additional storage tanks to market additional product grades at bulk plants. While this final rule minimizes the segregation of similar fuels, some additional segregation of products in the distribution system will still be required. The allowance that highway and NRLM diesel fuel meeting the same sulfur specification can be shipped fungibly until it leaves the terminal obviates the need for additional storage tanks in this segment of the distribution system except for the limited tankage at terminals necessary to handle 500 ppm sulfur interface fuel discussed above.[205] Today's final rule also allows 500 ppm NRLM diesel fuel to be mixed with high-sulfur NRLM (though it can no longer be sold as 500 ppm fuel).

However, we expect that the implementation of the 500 ppm standard for NRLM diesel fuel in 2007 will compel some bulk plants in those parts of the country still distributing heating oil as a separate fuel grade to install a second diesel storage tank to handle this 500 ppm NRLM fuel. These bulk plants currently handle only high-sulfur fuel and hence will need a second tank to continue their current practice of selling fuel into the heating oil market in the winter and into the nonroad market in the summer. We believe that

[203] We expect that only three types of fuel will be carried by such pipeline systems: jet fuel, 15 ppm diesel fuel, and gasoline (premium and regular). Premium and regular gasolines are always shipped next to each other so the interface between premium and regular gasoline can be cut into the batch of regular gasoline. Thus, whenever jet fuel is shipped it will abut 15 ppm diesel fuel on one end and gasoline on the other.

[204] *See* chapter 7.1.7 of the RIA regarding our analysis of the sulfur levels of this interface material. This analysis indicated that although the maximum sulfur specification of jet fuel 3,000 ppm, in-use jet fuel sulfur levels are frequently below 500 ppm.

[205] Including the refinery, pipeline, terminal, marine tanker, and barge segments of the distribution system.

some of these bulk plants will convert their existing diesel tank to 500 ppm fuel in order to avoid the expense of installing an additional tank. However, to provide a conservatively high estimate we assumed that 10 percent of the approximately 10,000 bulk plants in the U.S. (1,000) will install a second tank in order to handle both 500 ppm NRLM diesel fuel and heating oil.

The cost of an additional storage tank at a bulk plant is estimated at $90,000 and the cost of de-manifolding a delivery truck is estimated at $10,000.[206] In the NPRM, we estimated that each bulk plant that needed to install a new storage tank would need to de-manifold a single tank truck. Thus, the NPRM estimated the cost per bulk plant would be $100,000. Fuel distributors stated that the assumptions and calculations made by EPA in characterizing costs for bulk plant operators seem reasonable. However, they also stated that our estimate that a single tank truck would service a bulk plant is probably not accurate. No suggestion was offered regarding what might be a more appropriate estimate other than the number is likely to be much greater. Part of the reason why we estimated that only a single tank truck would need to be de-manifolded, is that we expected that due to the seasonal nature of the demand for heating oil versus nonroad fuel, it would primarily only be at the juncture of these two seasons that both fuels would need to be distributed in substantial quantities. We also expected that the small demand for heating oil in the summer and the small demand for nonroad fuel in the winter could be serviced using a single de-manifolded truck. The primary fuel distributed during a given season would be distributed by single compartment tank trucks. During the crossover between seasons, bulk plant operators would switch the fuel to which such single compartment tank trucks are used from nonroad to heating oil and back again.[207] Nevertheless, we agree that the subject bulk plant operators would likely be compelled to de-manifold more that a single tank truck. Lacking additional specific information, we believe that assuming that each bulk plant operator de-manifolds three tank trucks will provide a conservatively high estimate of the cost to bulk plant operators due to today's rule.

If all 1,000 bulk plants were to install a new tank and de-manifold three tank trucks, the cost for each bulk plant would be $120,000, and the total one-time capital cost would be $120,000,000. To provide a conservatively high estimate of the costs to bulk plant operators, we are assuming that all 1,000 bulk plants will do so. Amortizing the capital costs over 20 years, results in a estimated cost for tankage at such bulk plants of 0.1 cents per gallon of affected NRLM diesel fuel supplied. Although the impact on the overall cost of the program is small, the cost to those bulk plant operators who need to put in a separate storage tank may represent a substantial investment. Thus, we believe many of these bulk plants will search out other arrangements to continue servicing both heating oil and NRLM markets such as an exchange agreement between two bulk plants that serve a common area.

As a consequence of the end of the highway program's temporary compliance option (TCO) in 2010 and the disappearance of high-sulfur diesel fuel from much of the fuel distribution system resulting from the implementation of today's rule, we expect that storage tanks at many bulk plants that were previously devoted to 500 ppm TCO highway fuel and high-sulfur fuel will become available for dyed 15 ppm nonroad fuel service. Based on this assessment, we do not expect that a significant number of bulk plants will need to install an additional storage tank in order to provide dyed and undyed 15 ppm diesel fuel to their customers beginning in 2010 (the implementation date for the 15 ppm nonroad standard).[208] There could potentially be some additional costs related to the need for new tankage in some areas not already carrying 500 ppm fuel under the temporary compliance option of the highway diesel program and which continue to carry high sulfur fuel. However, we expect them to be minimal relative to the above 0.1 cent per gallon cost. Thus, we estimate that the total cost of additional storage tanks at bulk plants that will result from today's rule will be 0.1 cent per gallon of affected NRLM diesel fuel supplied.

The fourth impact on fuel distribution costs is a result of the requirement that high sulfur heating oil be marked beginning June 1, 2007 and that 500 ppm sulfur LM diesel produced by refiners or imported be marked from 2010 through 2012 outside of the Northeast/Mid-Atlantic Area and Alaska. The NPRM projected that there would be no capital costs associated with the proposed marker requirement. We proposed that the marker would be added at the refinery gate, and that the current requirement that non-highway fuel be dyed red at the refinery gate be made voluntary. Thus, we believed that the refiner's additive injection equipment that is currently used to inject red dye into off-highway diesel fuel could instead be used to inject the marker as needed. As a result of the allowance provided in today's final rule that the marker be added at the terminal rather than the refinery gate, and our reevaluation of the conditions for dye injection at the refinery, we are now assessing capital costs for terminals and refiners related to compliance with the fuel marker requirements.

Except for fuel that is distributed directly from a refiner's rack, today's final rule allows the marker to be added at the terminal rather than at the refinery as we proposed (*see* section IV.D for a discussion of the fuel marker requirements).[209] We expect that except for fuel dispensed directly from the refinery rack, the fuel marker will be added to at the terminal to avoid the potential for marked fuel to contaminate jet fuel during distribution by pipeline. Terminals that need to inject the fuel marker will need to purchase a new injection system, including a marker storage tank and a segregated line and injector for each truck loading station at which fuel that is required to be marked is dispensed. Terminals will still be subject to IRS red dye requirements, and thus will not be able to rededicate such injection equipment to inject the fuel marker. Due to concerns regarding the need to maintain a visible evidence of the presence of the fuel marker, today's rule also contains a requirement that nay fuel which contains the fuel marker also contains visible evidence of red dye. Furthermore, there is little chance to adapt parts of the red dye injection system (such as the feed lines and injectors) for the alternate injection of red dye and the fuel marker due to concerns that NRLM fuel become contaminated with the marker.

Terminal operators expressed concern regarding the potential burden on terminal operators from the capital costs of adding new additive injection equipment for heating oil. In response to these comments, today's rule includes provisions that exempt terminal operators from the fuel marker requirements in a geographic "Northeast/Mid-Atlantic Area" and

[206] This estimated cost includes the addition of a separate delivery system on the tank truck.

[207] To avoid sulfur contamination of NRLM fuel, the tank compartment would need to be flushed with some NRLM fuel prior to switching from carrying heating oil to NRLM fuel.

[208] *See* Section IV of today's preamble for additional discussion of our rational for this conclusion.

[209] A refinery rack functions similar to a terminal in that it distributes fuel by truck to wholesale purchaser consumers and retailers.

Alaska.[210] These provisions provide that any heating oil or 500 ppm sulfur LM diesel fuel that would otherwise be subject to the fuel marker requirements which is delivered to a retailer or wholesale-purchaser consumer inside the Northeast/Mid-Atlantic Area or Alaska does not need to contain the marker. The costs of the marker requirements for heating oil beginning in 2007 and for 500 ppm sulfur LM diesel fuel from 2010 through 2012 are discussed separately below.

The Northeast/Mid-Atlantic Area was defined to include the region where the majority of heating oil in the country is projected to continue to be supplied through the bulk distribution system (the Northeast and Mid-Atlantic). The vast majority of heating oil consumption in the U.S. will be within the Northeast/ Mid-Atlantic Area. Outside of the Northeast/Mid-Atlantic Area, we expect that only limited quantities of heating oil will be supplied, primarily from certain refiner's racks. We estimate that 30 refineries and transmix processor facilities outside of the Northeast/Mid-Atlantic Area will distribute heating oil from their racks (in limited volumes) on a sufficiently frequent basis to warrant the installation of a marker injection system at a total one time cost of $1,500,000.

Terminals outside of the Northeast/ Mid-Atlantic Area will mostly be located in areas without continued production and/or bulk shipment of heating oil. Consequently, any high sulfur diesel fuel they sell will typically be NRLM. Terminals located within the Northeast/Mid-Atlantic Area will not need to mark their heating oil, except for those few that choose to ship heating oil outside of the Northeast/Mid-Atlantic Area. The terminals most likely to install marker injection equipment will therefore be those in states outside the Northeast/Mid-Atlantic Area with modest markets for heating oil after the implementation of this program. As discussed in chapter 7 of the RIA, in analyzing the various situations, we project that fewer than 60 terminals nationwide will choose to install marker injection equipment at a total cost of $4,150,000.[211] The total capital cost to refiners and terminals to install marker injection equipment is estimated to be $5,650,000. Thus, the Northeast/Mid-Atlantic Area provisions in today's rule minimizes the number of terminals that will need to install additive injection equipment and its associated cost to comply with the marker requirement for heating oil.

In the NPRM we estimated that the cost to blenders of the fuel marker in bulk quantities would translate to 0.2 cents per gallon of fuel treated with the marker. This estimate was based on the fee charged by a major pipeline to inject red dye at the IRS concentration into its customers diesel fuel. We used this estimate because we lacked specific cost information on the proposed marker, and we believed that it provided a conservatively high estimate of marker cost. Since the proposal, we received input from a major distributor of fuel markers and dyes, regarding the cost of bulk deliveries of the specified fuel marker to terminals which translates to a cost of 0.03 cents per gallon of fuel treated with the marker. The volume of heating oil that we expect will need to be marked has also decreased substantially from that estimated in the NPRM due to the Northeast/Mid-Atlantic Area provisions. We estimate that 1.4 billion gallons of heating oil will be marked annually, for an annual marker cost of $425,000. In the NPRM, we projected that the cost of marking heating oil would continue for three years (2007–2010). Under today's final rule, heating oil must be marked indefinitely beginning in 2007, but only outside of the Northeast/Mid-Atlantic Area and Alaska.

Because heating oil outside of the Northeast/Mid-Atlantic Area is being marked to prevent its use in NRLM engines, for the purposes of estimating the impact of the marker requirement on the cost of the NRLM program we have spread the cost for the marker for heating oil over NRLM diesel fuel. Amortizing the capital costs of marker injection equipment over 20 years, results in an estimated cost of 0.006 cents per gallon of affected NRLM diesel fuel supplied. Spreading the cost of the marker over the volume of affected NRLM fuel results in an estimated cost of 0.003 cents per gallon of affected NRLM fuel. Adding the amortized cost of the injection equipment necessary to add the marker to heating oil and the cost or the marker results in a total estimated cost of the marker requirement for heating oil in today's rule of 0.01 cents per gallon of affected NRLM fuel.

The final NRLM rule also requires that 500 ppm L&M fuel produced at refineries or imported be marked from mid-2010 through mid-2012 outside of the Northeast/Mid-Atlantic Area and Alaska. The adoption of a 15 ppm sulfur standard for LM diesel fuel in 2012 in today's rule allows us to require that LM fuel be marked from 2010 through 2012 rather than from 2010 through 2014 as proposed (*see* section IV.A). In addition, the way in which the program was crafted to avoid requiring the fuel marker be added to heating oil in the Northeast/Mid-Atlantic Area and Alaska allows us to also provide that 500 ppm sulfur LM diesel fuel in these areas is not subject to the marker requirement (see section IV.D). We project that only a small number of refiners will produce 500 ppm sulfur diesel fuel subject to the marker requirements fuel and that it will not be shipped via pipeline. Thus, most of this fuel can be marked at the refinery, limiting the number of facilities which need to add marking equipment in response to this requirement. We estimate that 15 facilities will have to do so, at a cost of $60,000 each, for a total of $900,000. Amortizing this over the total volume of affected NRLM fuel produced from mid-2010 to mid-2012 at seven percent per year before taxes yields a cost for the LM marker requirement of 0.004 cent per gallon. Including the cost of the marker (0.03 cent per gallon of marked fuel) increases this cost to 0.01 cent per gallon of NRLM fuel.

We summed these various costs incurred to the distribution system over four different time periods. As shown in table VI.A–5, the total additional distribution cost will be 0.2 cent per gallon of NRLM fuel during the first step of the fuel program (from 2007 through 2010), 0.6 cents per gallon of NRLM fuel from 2010 to 2012 and from 2012 to 2014, and increase to 1.0 cent per gallon thereafter. A more detailed description of the costs associated with downgraded jet fuel and 15 ppm diesel fuel is presented in chapter 7 of the Final RIA.

[210] Small refiner and credit high sulfur NRLM will not be permitted to be sold in the area where terminals are not required to add the fuel marker to heating oil (the "Northeast/Mid-Atlantic Area"). See section IV.D.

[211] The estimated marker injection equipment costs include the cost of marker storage tanks, lines, and injectors.

TABLE VI.A–5.—SUMMARY OF DISTRIBUTION COSTS
[Cents per gallon]

Cause of increase in distribution costs	Time period over which costs apply			
	2007–2010	2010–2012	2010–2014	2014+
Distribution of additional NRLM volume	0.08	0.1	0.1	0.1
Distillate interface handling	0	0.4	0.4	0.8
Bulk plant storage tanks	0.1	0.1	0.1	0.1
Heating oil and L&M fuel marker	0.01	0.02	0.01	0.01
Total	0.2	0.6	0.6	1.0

3. Cost of Lubricity Additives

Hydrotreating diesel fuel tends to reduce the natural lubricating quality of diesel fuel, which is necessary for the proper functioning of certain fuel system components. There are a variety of fuel additives which can be used to restore diesel fuel's lubricating quality. These additives are currently used to some extent in highway diesel fuel. We expect that the need for lubricity additives that will result from the proposed 500 ppm sulfur standard for NRLM diesel fuel will be similar to that for highway diesel fuel meeting the current 500 ppm sulfur cap standard.[212] Industry experience indicates that the vast majority of highway diesel fuel meeting the current 500 ppm sulfur cap does not need lubricity additives. Therefore, we expect that the great majority of NRLM diesel fuel meeting the proposed 500 ppm sulfur standard will also not need lubricity additives. In estimating lubricity additive costs for 500 ppm diesel fuel, we assumed that fuel suppliers will use the same additives at the same concentration as we projected will be used in 15 ppm highway diesel fuel. Based on our analysis of this issue for the 2007 highway diesel fuel program, the cost per gallon of the lubricity additive is about 0.2 cents. This level of use is likely conservative, as the amount of lubricity additive needed increases substantially as diesel fuel is desulfurized to lower levels. We also project that only five percent of all 500 ppm NRLM diesel fuel will require the use of a lubricity additive. Thus, we project that the cost of additional lubricity additives for the affected 500 ppm NRLM diesel fuel will be 0.01 cent per gallon. See the Final RIA for more details on the issue of lubricity additives. We have no reason to expect that the implementation of today's NRLM sulfur standards will impact diesel properties other than fuel lubricity in such a way as to require the use of additives.

We project that all NRLM fuel meeting a 15 ppm cap will require treatment with lubricity additives. Thus, the projected cost will be 0.2 cent per affected gallon of 15 ppm NRLM fuel.

4. How EPA's Projected Costs Compare to Other Available Estimates

Historically, the price of highway diesel fuel meeting a 500 ppm sulfur cap has exceeded that of high sulfur diesel fuel, ranging from 0–5 cents per gallon from 1995–99 and averaging 2.2 cents per gallon over this time period (*see* chapter 7 of the Final RIA). Fuel prices are often a function of market forces which might not reflect the cost of producing the fuel. Still, given this is a five-year average price difference, it is likely a reasonable indication of the cost of reducing highway diesel fuel sulfur to 500 ppm. Once the small refiner provisions applicable to 500 ppm fuel expire in 2010, we project that the total cost of the 500 ppm NRLM fuel cap will be 2.4 cents per gallon, well within the range of the historical highway-high sulfur fuel price difference. This similarity exists despite changes in a number of factors. One, our projection of future natural gas costs are significantly higher than those existing during the above price comparison. Two, the refineries producing highway diesel fuel historically likely did so because they faced lower costs than those refineries continuing to produce high sulfur distillate. Three, desulfurization catalyst efficiency has improved dramatically since the highway units were installed and significant operating experience has been obtained on highway units. Four, inflation since the early 1990's will have increased the cost of constructing the same hydrotreater. Five, and perhaps most importantly, the construction of some new hydrotreaters to produce 15 ppm highway diesel fuel will allow the existing hydrotreaters to produce 500 ppm NRLM fuel at no capital cost. Thus, there are at least five significant factors, two of which would tend to decrease costs and three of which would tend to increase costs. It is not surprising that these factors could counter-balance each other, leading to the conclusion that the 500 ppm cap could be extended to NRLM fuel at roughly the same cost as for highway diesel fuel.

The only existing market for 15 ppm diesel fuel is a niche market for fleets and the prices for this fuel likely bear little resemblance to the costs of the 15 ppm highway or NRLM caps. Thus, the only cost comparisons which can be made are those between engineering studies. One such study was performed by Mathpro for the Engine Manufactures Association (EMA). Mathpro estimated the cost of controlling the sulfur content of highway and NRLM fuel to levels consistent with both 500 ppm and 15 ppm cap standards.[213] A detailed evaluation of the Mathpro costs is presented in the Final RIA. There are a number of aspects of the study that make direct comparisons between its estimates and our cost estimates difficult. Nonetheless, a crude comparison of 15 ppm costs indicates that our average cost range of 5.7–5.9 cent per gallon is quite similar to the 5.4–6.6 cents per gallon cost range estimated by Mathpro.

The other available study of 15 ppm fuel costs was performed by Baker and O'Brien for API and submitted in response to the nonroad NPRM. Baker and O'Brien analyzed two NRLM fuel control scenarios, but neither one matched today's final NRLM fuel program. The scenario closest to today's program assumed that a NRLM fuel would be capped at 15 ppm in 2008. In this case, Baker and O'Brien projected that the refinery-specific cost of 15 ppm NRLM fuel would range from 4–17 cents per gallon. This is higher than our projected range of 2–14 cents per gallon. In addition, as described in the next

[212] Please refer to section IV in today's preamble for additional discussion regarding our projections of the potential impact on fuel lubricity of this proposed rule.

[213] Hirshfeld, David, MathPro, Inc., "Refining economics of diesel fuel sulfur standards," performed for the Engine Manufactuers Association, October 5, 1999.

section, Baker and O'Brien projected that the volume of NRLM fuel produced at these costs would not fully satisfy NRLM fuel demand. Presumably, totally fulfilling NRLM fuel demand with domestic production would have cost more.

Baker and O'Brien described portions of their cost methodology and indicated some general assumptions which they made during the study. However, the absence of detail prevents any detailed comparisons of their results to ours. It was clear from their report, though, that Baker and O'Brien made a number of pessimistic assumptions about refiners' willingness to invest in desulfurization capacity and that this limited the number of refineries which they assumed would invest to meet the NRLM sulfur caps. This inevitably led to higher projected costs (and lower production volumes), than if all refineries had been considered. Thus, it is not surprising that they would derive slightly higher costs for a much smaller volume of fuel. A more detailed evaluation of the Baker and O'Brien cost estimates can be found in the Final RIA and RTC.

5. Supply of Nonroad, Locomotive and Marine Diesel Fuel

We have developed today's NRLM fuel program to minimize its impact on the supply of distillate fuel. For example: We have split the control of NRLM fuel to 15 ppm sulfur into two steps, providing 8 years of leadtime for the final step. We are proposing to provide flexibility to refiners through the availability of banking and trading provisions. We have provided relief for small refiners and hardship relief for any qualifying refiner. We are also allowing 500 ppm diesel fuel generated in the distribution system to be sold as L&M fuel indefinitely.

In the NPRM, we evaluated four possible reasons why refiners might reduce their production of NRLM fuel: (1) Chemical processing losses during the desulfurization process, (2) refiners might leave the NRLM fuel market, (3) refiners might stop operations altogether (*i.e.*, shut down), and (4) refiners might remove certain blendstocks from the fuel pool to reduce desulfurization costs. In all four cases, we concluded that the answer was no, that the supply of NRLM fuel would likely remain adequate after implementation of the proposed fuel program. All of these findings started from the position that there would be adequate supply of diesel fuel after implementation of the 2007 highway diesel fuel program.

Several commenters, namely API and NPRA, took issue with the above four sets of arguments, as well as with our conclusion that refiners would not reduce NRLM fuel production. While not requesting any changes to the 2007 highway diesel fuel program, they reiterated previous concerns that supply shortages could occur under the highway diesel fuel program, even without the added challenge of producing low sulfur NRLM fuel. The primary basis for their comments was a study they had sponsored by Baker and O'Brien, which evaluated the costs and likely supply impacts of the proposal.

Baker and O'Brien evaluated two NRLM fuel scenarios: (1) A 15 ppm NRLM fuel cap starting in 2008, and (2) a 500 ppm NRLM fuel cap starting in 2008, followed by a 15 ppm cap only for nonroad fuel in 2010. First, Baker and O'Brien projected that 13 refineries with a total crude oil capacity of 971,000 barrels per day would close in response to the 2007 highway rule, roughly half in 2006 and half in 2010. (Total U.S. refining capacity is currently 16 million barrels per day.) Then Baker and O'Brien projected that adding a 15 ppm NRLM cap would cause all of the refineries shutting down in 2010 to close in 2008, plus one additional refinery (for a total of 14). Delaying the 15 ppm cap until 2010 and leaving L&M fuel at 500 ppm reduced the number of refineries projected to close in 2008, but did not change Baker and O'Brien's projection that 14 refineries would close by 2010. Given the fact that Baker and O'Brien projected the same number of refinery closures for scenarios #1 and #2, it is reasonable to assume that they would project similar results for today's final NRLM fuel program.

TABLE VI.A–6.—PROJECTED REFINERY CLOSURES: API SPONSORED STUDY BY BAKER AND O'BRIEN

	No. of refineries		Lost crude capacity (1000 bbl/day)	
	2008	2010	2008	2010
2007 Highway Fuel Program	[214] 8	13	504	971
Plus One-Step 15 ppm NRLM Program	14	14	1043	1043
Plus Two-Step NRLM Program	12	14	924	1043

As a result of these refinery closures, Baker and O'Brien projected shortfalls in 15 and 500 ppm supply domestic refiners. The net shortfalls are shown in table VI.A–7 below. Baker and O'Brien stated that imports would have to make up the shortfall, with potentially high price impacts.

TABLE VI.A–7.—PROJECTED SHORTFALL IN NEAR-TERM DIESEL FUEL SUPPLY

[1000 barrels per day]

	15 ppm Fuel		500 ppm Fuel	
	2008	2010	2008	2010
2007 Highway Fuel Program	359	579	308	22
Plus One-Step 15 ppm NRLM Program	684	930	165	0
Plus Two-Step NRLM Program	351	639	481	82

[214] Closure would occur at the beginning of the 15 ppm highway fuel program, or 2006.

To put these projected shortfalls in context, Baker and O'Brien projects total diesel fuel demand to be 3.3 million barrels per day in this timeframe (slightly lower than our own projection summarized above). Thus, these projected shortfalls total roughly 10–20 percent of total diesel fuel demand, which if true, would be very significant.

We evaluated the Baker and O'Brien study and their findings. Baker and O'Brien made very pessimistic assumptions regarding the likelihood that refiners would invest in desulfurization capacity. Their judgment that a refinery would close rather than invest also was apparently based only on what they perceived to be excessively high desulfurization costs. Baker and O'Brien presents no information regarding the location of these refineries, the competition they face, costs related to closing down, nor the profits that they would forego by closing. Baker and O'Brien also makes no mention of EPA's special provisions for refiners facing economic hardship, nor the small refiner provisions.

We believe that it is not possible to project refinery closures without considering these factors. This is supported by comments made in response to our proposal of the 2007 highway diesel fuel program by Mathpro and the National Economic Research Associates. While we are aware of a couple of refineries that are being offered for sale and whose plans for producing low sulfur fuels are uncertain, we have no indications of as many as eight refineries closing in 2006 in response to the highway fuel program. In addition, despite uncertainties at a few refineries, refiners' pre-compliance reports for the highway fuel program indicate that they are planning to produce a sufficient supply of 15 and 500 ppm highway diesel fuel from 2006–2010. Therefore, there is ample evidence that Baker and O'Brien's projections for the highway diesel fuel program are overly pessimistic. It therefore appears likely that their projection that the NRLM fuel program will cause an additional refinery to close is also overly pessimistic. The reader is referred to the RTC for a summary of these comments and our detailed response to them.

In their comments, API also challenged our findings that refiners would maintain sufficient supply under the proposed NRLM fuel program. After a careful review of their comments and other information newly available since the NPRM, we do not believe that the arguments presented by API and NPRA justify changing our position that (1) chemical processing losses during the desulfurization process will be very small, (2) refiners will be unlikely to leave the NRLM fuel market, and (3) refiners are unlikely to shut down due to this rule.

Regarding point #1, the distillate material lost during desulfurization, our position is that the amount lost is small (two percent), and most of it is lost in the form of naphtha which can be blended into gasoline. Refiners can then adjust their mix of gasoline and distillate production to compensate. API claimed that in the winter, refiners were already at maximum distillate production and could not shift any additional heavy gasoline material into the distillate pool. API did not present any evidence that this is in fact the case. The fact that some refiners actually crack distillate material into gasoline makes it difficult to accept their position.

Regarding point #2, refiners leaving the NRLM fuel market, we argued that the only high sulfur distillate market remaining after 2007 was heating oil. Heating oil demand is flat or declining over time. We project that over 30 domestic refiners will still be able to produce heating oil after 2007, while other refiners will be able to produce sufficient quantities of NRLM fuel. If more refiners choose to produce heating oil, this market will be oversupplied and prices will drop significantly. Exporting high sulfur distillate is a possibility for some refiners, but this entails both transport costs, as well as relatively low prices overseas. Thus, a decision to not invest in NRLM fuel desulfurization has to be compared to the losses involved with the other options. API argued that some refiners face much higher desulfurization costs than others and this would lead those refiners to leave the NRLM fuel market. API did not estimate the losses that refiners would entail when they left the market. Studies performed for the highway fuel program indicate that these losses can be quite significant and inappropriate conclusions can be drawn if they are ignored. The highway program pre-compliance reports also indicate that some highway fuel refiners are planning on leaving the highway fuel market in 2006, while others will enter it for the first time. Decisions to stay in or leave the NRLM fuel market are analogous. We have no reason to believe refiners would approach this market any differently than the highway market.

Regarding point #3, refineries shutting down, API again pointed towards the high costs faced by some refineries and the fact that a number of refineries have shut down over the past ten years. There have been a number of refinery closures over the past decade, though the trend has slowed considerably. API pointed towards two specific refineries which identified EPA's gasoline and diesel fuel sulfur controls as prime reasons for their shutting down. A closer look at these situations showed that the future capital investment related to the sulfur controls could have been a contributing factor. However, these refineries faced many other challenges and the timing of their closure (2000 and 2001, respectively) showed that the EPA rules were not the direct cause. The refiner involved did not approach EPA concerning any relief from the rules' requirements due to economic hardship. Thus, the connection between their closure and our sulfur controls appears even more tenuous.

Another example of a refinery closure unrelated to desulfurization costs was Shell's recent decision to close their refinery in Bakersfield, California. The reason was an insufficient supply of crude oil being produced locally.

Analogous to a decision to leave the NRLM fuel market, shutting down completely involves the total loss of any profit being made on the production of other fuels. API presented no economic calculations or projections showing that it would be in the best interest of any refiner to shut down rather than invest in NRLM fuel desulfurization.

This leaves point #4, that refiners might shift NRLM fuel blendstocks to other markets. This is really only an issue if the blendstocks are shifted to a non-distillate market.[215] The most likely place that NRLM fuel blendstocks might be shifted is to the residual fuel market. In particular, heavy (material with high densities and high distillation temperatures) LCO and LCGO could be shifted to residual fuel using existing refining equipment. The heavy portions of these two blendstocks contain the greatest concentrations of sulfur which is the most difficult to remove. Shifting this material to residual fuel, which currently does not have a sulfur standard, would reduce the size and cost of desulfurization equipment needed to meet a 15 ppm cap. Or, it would increase the volume of 15 ppm NRLM fuel which could be produced in an existing hydrotreater.

To evaluate this possibility, we estimated the cost of processing LCO (the worse of the two blendstocks) into 15 ppm diesel fuel for each domestic refinery. On average, desulfurizing LCO to 15 ppm sulfur cost 11.4 cents per

[215] Shifting NRLM fuel blendstocks to heating oil is essentially the same as leaving the NRLM market, which was discussed under Point #2 above.

gallon. However, in some cases, this cost reached 15 cents per gallon. The cost to process heavy LCO could be twice these amounts, since the concentration of both total sulfur and the most difficult to remove sulfur are concentrated in the heaviest molecules.

A review of historic fuel prices showed that residual fuel is usually priced 25–30 cents per gallon less than diesel fuel. The highest incremental desulfurization costs for heavy LCO could potentially exceed this loss. Thus, a few refiners could find it economical to shift a portion of their LCO to the residual fuel market. The U.S. residual fuel market is small relative to the distillate fuel market, flat, and already being fulfilled. Worldwide, the residual fuel market is shrinking. Thus, it is unlikely that large volumes of LCO could leave the NRLM fuel market. However, we cannot rule out the possibility that some LCO, particularly that produced by capital-strapped refiners, could be shifted to residual fuel. To estimate the upper limit of this shift, we estimated the volume of heavy LCO produced by refineries whose LCO processing costs exceeded 12 cents per gallon and which were not owned by large, integrated oil companies or small refiners. This costly, heavy LCO represents 0.4 percent of total NRLM fuel demand, a very small volume. In this case, we would expect that this loss could easily be made up by increased imports of 15 ppm diesel fuel or domestic refiners facing lower 15 ppm NRLM fuel costs.

Overall, we expect that domestic refiners will continue to produce sufficient supplies of NRLM fuel. The greatest potential for near term loss will be due to the possibility that some refiners might decide to limit their capital investment in desulfurization capacity by shifting some heavy LCO to the residual fuel market.

Fuel-Only Control Programs: The potential supply impacts of a long-term 500 ppm NRLM cap would necessarily be less than those of today's final NRLM fuel program. In particular, desulfurizing "difficult" blendstocks, like LCO, to 500 ppm is not technically challenging and does not have the potential to cost more than would be lost in shifting LCO or heavy LCO to residual fuel. The capital investment to meet a 500 ppm cap is also half of that needed to meet a 15 ppm cap or less. Thus, the likelihood that raising this capital would prove difficult is much less. Given that we expect the final fuel program to have a very minimal impact on supply, a 500 ppm NRLM cap would be negligible.

The potential impact of a long-term 15 ppm NRLM cap is the same as that for today's final fuel program.

6. Fuel Prices

It is well known that it is difficult to predict fuel prices in absolute terms with any accuracy. The price of crude oil dominates the cost of producing gasoline and diesel fuel. Crude oil prices have varied by more than a factor of two in the past two years. In addition, unexpectedly warm or cold winters can significantly affect heating oil consumption, which affects the amount of gasoline produced and the amount of distillate material available for diesel fuel production. Economic growth, or its lack, affects fuel demand, particularly for diesel fuel. Finally, both planned and unplanned shutdowns of refineries for maintenance and repairs can significantly affect total fuel production, inventory levels and resulting fuel prices.

Predicting the impact of any individual factor on fuel price is also difficult. The overall volatility in fuel prices limits the ability to determine the effect of a factor which changed at a specific point in time which might have led to the price change, as other factors continue to change over time. Occasionally, a fuel quality change, such as reformulated gasoline or a 500 ppm cap on diesel fuel sulfur content, only affects a portion of the fuel pool. In this case, an indication of the impact on price can be inferred by comparing the prices of the two fuels at the same general location over time. However, this is still only possible after the fact, and cannot be done before the fuel quality change takes place.

Because of these difficulties, EPA has generally not attempted to project the impact of its rules on fuel prices. However, in response to Executive Order 13211, we are doing so here.[216] To reflect the inherent uncertainty in making such projections, we developed three projections for the potential impact of the proposed fuel program on fuel prices. The range of potential long-term price increases are shown in table VI.A–8. (Due to their similarity, we have grouped the potential price impacts for similar quality fuels in the 2010–2012 and 2012–2014 time periods.) Short-term price impacts are highly volatile, as are short-term swings in absolute fuel prices, and much too dependent on individual refiners' decisions, unexpected shutdowns, etc. to be predicted even with broad ranges.

TABLE VI.A–8.—RANGE OF POSSIBLE TOTAL DIESEL FUEL PRICE INCREASES

[Cents per gallon][a]

	Maximum operating cost	Average total cost	Maximum total cost
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007–2010)			
PADDs 1 and 3	2.9	1.8	4.5
PADD 2	3.0	2.5	3.8
PADD 4	3.7	3.5	6.1
PADD 5	1.2	1.5	1.5
15 ppm Sulfur Cap: NRLM Fuel (2010–2014)			
PADDs 1 and 3	5.6	5.7	9.4
PADD 2	7.3	7.4	10.8
PADD 4	7.9	12.6	13.6
PADD 5	4.5	5.1	5.2

[216] Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001).

TABLE VI.A–8.—RANGE OF POSSIBLE TOTAL DIESEL FUEL PRICE INCREASES—Continued

[Cents per gallon][a]

	Maximum operating cost	Average total cost	Maximum total cost
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	7.7	6.3	9.8
PADD 2	7.7	7.9	11.2
PADD 4	8.3	13.0	13.9
PADD 5	5.1	6.9	7.3

Notes: [a] At the current wholesale price of approximately $1.00 per gallon, these values also represent the percentage increase in diesel fuel price.

The lower end of the range assumes that prices within a PADD increased to reflect the highest operating cost increase faced by any refiner in that PADD (please see the Final RIA for details on this methodology). This refiner with the highest operating cost will not recover any of his invested capital, but all other refiners will recover some or all of their investment. In this case, the price of NRLM fuel will increase in 2007 by 1–3 cents per gallon, depending on the area of the country. In 2010, the price of 15 ppm NRLM fuel will increase a total of 3–7 cents per gallon. In 2014, under this pricing scenario, 15 ppm NRLM fuel prices will increase slightly, to 4–7 cents per gallon. The increase in 2014 is due to the expiration of the small refiner provisions, as well as the fact that 500 ppm fuel created in the distribution system can no longer be sold to the land-based nonroad market.

The mid-range estimate of price impacts assumes that prices within a PADD increase by the average refining and distribution cost within that PADD, including full recovery of capital (at seven percent per annum before taxes). Lower cost refiners will recover more than their capital investment, while those with higher than average costs recover less. Under this assumption, the price of NRLM fuel will increase in 2007 by 1–3 cents per gallon, depending on the area of the country. In 2010, the price of 15 ppm NRLM fuel will increase a total of 4–11 cents per gallon. In 2014, under this pricing scenario, 15 ppm NRLM fuel prices will increase slightly, to 5–11 cents per gallon.

The upper end estimate of price impacts assumes that prices within a PADD increase by the maximum total refining and distribution cost of any refinery within that PADD, including full recovery of capital (at seven percent per annum before taxes). All other refiners will recover more than their capital investment. Under this assumption, the price of NRLM fuel will increase in 2007 by 1–4 cents per gallon, depending on the area of the country. In 2010, the price of 15 ppm NRLM fuel will increase a total of 4–13 cents per gallon. In 2014, under this pricing scenario, 15 ppm NRLM fuel prices will increase further to 6–13 cents per gallon. All these potential price impacts for 500 and 15 ppm fuel, relative to those projected in the NPRM, reflect the differences in cost estimates discussed above.

There are a number of assumptions inherent in all three of the above price projections. First, both the lower and upper limits of the projected price impacts described above assume that the refinery facing the highest compliance costs is currently the price setter in their market. This is a worse case assumption which is impossible to validate. Many factors affect a refinery's total costs of fuel production. Most of these factors, such as crude oil cost, labor costs, age of equipment, etc., are not considered in projecting the incremental costs associated with lower NRLM diesel fuel sulfur levels. Thus, current prices may very well be set in any specific market by a refinery facing lower incremental compliance costs than other refineries. This point was highlighted in a study by the National Economic Research Associates (NERA) for AAM of the potential price impacts of EPA's 2007 highway diesel fuel program.[217] In that study, NERA criticized the above referenced study performed by Charles River Associates, *et al.* for API, which projected that prices will increase nationwide to reflect the total cost faced by the U.S. refinery with the maximum total compliance cost of all the refineries in the U.S. producing highway diesel fuel. To reflect the potential that the refinery with the highest projected compliance costs under the maximum price scenario is not the current price setter, we included the mid-point price impacts above. It is possible that even the lower limit price impacts are too high, if the conditions exist where prices are set based on operating costs alone. However, these price impacts are sufficiently low that considering even lower price impacts was not considered critical to estimating the potential economic impact of this rule.

Second, we assumed in some cases that a single refinery's costs could affect fuel prices throughout an entire PADD. While this is a definite improvement over analyses which assume that a single refinery's costs could affect fuel prices throughout the entire nation, it is still conservative. High cost refineries are more likely to have a more limited geographical impact on market pricing than an entire PADD. In many cases, high cost refiners continue to operate simply because they are in a niche location where transportation costs limit competition.

Third, by focusing solely on the cost of desulfurizing NRLM diesel fuel, we assume that the production of NRLM diesel fuel is independent of the production of other refining products, such as gasoline, jet fuel and highway diesel fuel. However, this is clearly not the case. Refiners have some flexibility to increase the production of one product without significantly affecting the others, but this flexibility is quite limited. It is possible that the relative economics of producing other products could influence a refiner's decision to increase or decrease the production of NRLM diesel fuel under today's fuel program. It is this price response that causes fuel supply to match fuel demand. And, this response in turn could increase or decrease the price impact relative to those projected above.

Fourth, all three of the above price projections are based on the projected cost for U.S. refineries of meeting the NRLM fuel sulfur caps. Thus, these price projections assume that imports of NRLM fuel, which are currently significant in the Northeast, are available at roughly the same cost as those for U.S. refineries in PADDs 1 and

[217] "Potential Impacts of Environmental Regulations on Diesel Fuel Prices," NERA, for AAM, December 2000.

3. We have not performed any analysis of the cost of lower sulfur caps on diesel fuel produced by foreign refiners. However, there are reasons to believe that imports of 500 and 15 ppm NRLM diesel fuel will be available at prices in the ranges of those projected for U.S. refiners.

One recent study analyzed the relative cost of lower sulfur caps for Asian refiners relative to those in the U.S., Europe and Japan.[218] It concluded that costs for Asian refiners will be comparatively higher, due to the lack of current hydrotreating capacity at Asian refineries. This conclusion is certainly valid when evaluating lower sulfur levels for highway diesel fuels which are already at low levels in the U.S., Europe and Japan and for which refineries in these areas have already invested in hydrotreating capacity. It appears to be less valid when assessing the relative cost of meeting lower sulfur standards for NRLM fuels and heating oils which are currently at much higher sulfur levels in the U.S., Europe and Japan. All refineries face additional investments to remove sulfur from these fuels and so face roughly comparable control costs on a per gallon basis.

One factor arguing for competitively priced imports is the fact that refinery utilization rates are currently higher in the U.S. and Europe than in the rest of the world. The primary issue is whether overseas refiners will invest to meet tight sulfur standards for U.S., European and Japanese markets. Many overseas refiners will not invest, instead focusing on local, higher sulfur markets. However, many overseas refiners focus on exports. Both Europe and the U.S. are moving towards highway and nonroad diesel fuel sulfur caps in the 10–15 ppm range. Europe is currently and projected to continue to need to import large volumes of highway diesel fuel. Thus, it seems reasonable to expect that a number of overseas refiners will invest in the capacity to produce some or all of their diesel fuel at these levels. Many overseas refiners also have the flexibility to produce 10–15 ppm diesel fuel from their cleanest blendstocks, as most of their available markets have less stringent sulfur standards. Thus, there are reasons to believe that some capacity to produce 10–15 ppm diesel fuel will be available overseas at competitive prices. If these refineries were operating well below capacity, they might be willing to supply complying product at prices which only reflect incremental operating costs. This could hold prices down in areas where importing fuel is economical. However, it is unlikely that these refiners could supply sufficient volumes to hold prices down nationwide. Despite this expectation, to be conservative, in the refining cost analysis conducted earlier in this chapter, we assumed no imports of 500 ppm or 15 ppm NRLM diesel fuel. All 500 ppm and 15 ppm NRLM fuel was produced by domestic refineries. This raised the average and maximum costs of 500 ppm and 15 ppm NRLM diesel fuel and increased the potential price impacts projected above beyond what would have been projected had we projected that 5–10 percent of NRLM diesel fuel will be imported at competitive prices.

Fuel-Only Control Programs: We used the same methodology to estimate the potential price impacts for stand-alone 500 ppm and 15 ppm NRLM fuel programs. The potential price impacts of long-term 500 ppm and 15 ppm NRLM caps would be the same as those shown in table VI.A–8 above for the 500 ppm NRLM cap in 2007 and for the 15 ppm NRLM cap in 2014 and beyond, respectively.

B. Cost Savings to the Existing Fleet From the Use of Low Sulfur Fuel

We estimate that reducing fuel sulfur to 500 ppm would reduce engine wear and oil degradation to the existing nonroad diesel equipment fleet and that a further reduction to 15 ppm sulfur would result in even greater reductions. This reduction in wear and oil degradation would provide a dollar savings to users of nonroad equipment. The cost savings would also be realized by the owners of future nonroad engines that are subject to the standards in this proposal. As discussed below, these maintenance savings have been conservatively estimated to be greater than 3 cents per gallon for the use of 15 ppm sulfur fuel when compared to the use of today's unregulated nonroad diesel fuel. A summary of the range of benefits from the use of low-sulfur fuel is presented in Table VI.B–1.[219]

TABLE VI.B–1.—ENGINE COMPONENTS POTENTIALLY AFFECTED BY LOWER SULFUR LEVELS IN DIESEL FUEL[a]

Affected components	Effect of lower sulfur	Potential impact on engine system
Piston Rings	Reduced corrosion wear	Extended engine life and less frequent rebuilds.
Cylinder Liners	Reduced corrosion wear	Extended engine life and less frequent rebuilds.
Oil Quality	Reduced deposits, reduced acid build-up, and less need for alkaline additives.	Reduce wear on piston ring and cylinder liner and less frequent oil changes.
Exhaust System (tailpipe)	Reduced corrosion wear	Less frequent part replacement.
Exhaust Gas Recirculation System	Reduced corrosion wear	Less frequent part replacement

Notes: [a] The degree to which all of these benefits may occur for any specific engine will vary. For example, the impact of high sulfur fuel on piston rings, cylinder liners and oil quality are somewhat interdependent. To the extent an end-user lengthens the oil drain interval, the benefit of the low sulfur fuel on piston ring and cylinder liner wear will be lessened (though not eliminated). For users who do not alter oil drain intervals, the benefit of low sulfur fuel on extending piston ring and cylinder liner wear will be greater. The benefit of low sulfur fuel on reducing exhaust system and EGR system corrosion are independent of oil drain intervals.

The monetary value of these benefits over the life of the equipment will depend upon the length of time that the equipment operates on low-sulfur diesel fuel and the degree to which engine and equipment manufacturers specify new maintenance practices and the degree to which equipment operators change engine maintenance patterns to take advantage of these benefits. For equipment near the end of its life in the 2008 time frame, the benefits will be quite small. However, for equipment produced in the years immediately preceding the introduction of 500 ppm sulfur fuel, the savings would be substantial. Additional savings would

[218] "Cost of Diesel Fuel Desulfurization In Asian Refineries," Estrada International Ltd., for the Asian Development Bank, December 17, 2002.

[219] *See* Heavy-duty 2007 Highway Final RIA, Chapter V.C.5, and "Study of the Effects of Reduced Diesel Fuel Sulfur Content on Engine Wear," EPA report # 460/3–87–002, June 1987.

be realized in 2010 when the 15 ppm sulfur fuel would be introduced.

We estimate the single largest savings would be the impact of lower sulfur fuel on oil change intervals. The RIA presents our analysis for the oil change interval extension which would be realized by the introduction of 500 ppm sulfur fuel in 2007, as well as the additional oil extension which would be realized with the introduction of 15 ppm sulfur nonroad diesel fuel in 2010. As explained in the RIA, these estimates are based on our analysis of publically available information from nonroad engine manufacturers. Due to the wide range of diesel fuel sulfur which today's nonroad engines may see around the world, engine manufacturers specify different oil change intervals as a function of diesel sulfur levels. We have used this data as the basis for our analysis. Taken together, when compared to today's relatively high nonroad diesel fuel sulfur levels, we estimate the use of 15 ppm sulfur fuel will enable an oil change interval extension of 35 percent from today's products.

We received comments on our estimated maintenance savings primarily from a number of end-user groups (*e.g.*, equipment dealers, equipment rental organizations, farming organizations). Several commenters believed our estimates were too high, and one commenter believed the estimate was too low. However, all of the commenters who believed our cost savings estimates were too high provided no data to support their comments, beyond unsubstantiated opinions, nor did they comment on EPA's substantial related technical analysis.

The commenter who suggested the estimates were too low provided an example cost estimate for existing oil change intervals which, if used in our analysis, would have resulted in an estimated cost savings 4 times EPA's estimate. We have not changed our estimate based on the comments we received.

We present here a fuel operating cost savings attributed to the oil change interval extension in terms of a cents per gallon operating cost. We estimate that an oil change interval extension of 31 percent, as would be enabled by the use of 500 ppm sulfur fuel in 2007, results in a fuel operating costs savings of 2.9 cents per gallon for the nonroad fleet. We estimate an additional cost savings of 0.3 cents per gallon for the oil change interval extension which would be enabled by the use of 15 ppm sulfur beginning in 2010. Thus, for the nonroad fleet as a whole, beginning in 2010 nonroad equipment users can realize an operating cost savings of 3.2 cents per gallon compared to today's engine. This means that the end cost to the typical user for 15 ppm sulfur fuel is approximately 3.8 cents per gallon (7.0 cent per gallon cost for fuel minus 3.2 cent per gallon maintenance savings). For a typical 100 horsepower nonroad engine this represents a net present value lifetime savings, excluding the higher fuel costs, of more than $500.

These savings will occur without additional new cost to the equipment owner beyond the incremental cost of the low-sulfur diesel fuel, although these savings are dependent on changes to existing maintenance schedules. Such changes seem likely given the magnitude of the savings. There are many mechanisms by which end-users could become aware of the opportunity to extend oil drain intervals. First, it is typical practice for engine and equipment manufacturers to issue service bulletins regarding lubrication and fueling guidance for end-users.[220] Manufacturers provide these service bulletins to equipment dealerships and large equipment customers (such as rental companies). In addition, the equipment and end-user industries have a number of annual conferences which are used to share information, including information regarding appropriate engine and equipment maintenance practices. The end-user conferences are also designed to help specific industries and business reduce operating costs and maximize profits, which would include information on equipment maintenance practices. There are trade journals and publications which provide information and advice to their users regarding proper equipment maintenance. Finally, some nonroad users perform routine oil sample analysis in order to determine appropriate oil drain intervals, and in some cases to monitor overall engine wear rates in order to determine engine rebuild needs.[221] We have not estimated the value of the savings from all of the benefits listed in table VI.B–1, and therefore we believe the 3.2 cents per gallon savings is conservative as it only accounts for the impact of low sulfur fuel on oil change intervals. While some of these benefits are impacted by changes in oil change interval, a number are independent and not included in our cost savings estimate.

[220] For example, Appendix A of EPA Memorandum "Estimate of the Impact of Low Sulfur Fuel on Oil Change Intervals for Nonroad Diesel Equipment" contains a service bulletin from a nonroad diesel engine manufacturer. Copy of memo available in EPA Air Docket A–2001–28, item II–A–194.

[221] For example, Appendix C of EPA Memorandum "Estimate of the Impact of Low Sulfur Fuel on Oil Change Intervals for Nonroad Diesel Equipment", which indicates Caterpillar recommends owners use Scheduled Oil Sampling analysis as the best means for users to determine appropriate oil change intervals. Copy of memo available in EPA Air Docket A–2001–28, item II–A–194.

C. Engine and Equipment Cost Impacts

The following sections briefly discuss the various engine and equipment cost elements considered for this final rule and present the total costs we have estimated. The reader is referred to the RIA for a complete discussion. Estimated engine and equipment costs depend largely on both the size of the piece of equipment and its engine, and on the technology package being added to the engine to ensure compliance with the new Tier 4 standards. The wide size variation (*e.g.*, engines under 4 horsepower through engines above 2500 horsepower) and the broad application variation (*e.g.*, lawn equipment through large mining trucks) that exists in the nonroad industry makes it difficult to present here an estimated cost for every possible engine and/or piece of equipment. Nonetheless, for illustrative purposes, we present some examples of engine and equipment cost impacts throughout this discussion. Note that the costs presented here are for those nonroad engines and equipment that are mobile nonroad equipment and are, therefore, subject to nonroad engine standards. These costs would not apply for that equipment that is stationary—some portion of some equipment segments such as generator sets, pumps, compressors—and not subject to nonroad engine standards. The analysis summarized here is presented in detail in chapter 6 of the RIA.

Note that the costs presented here do not reflect any savings that are expected to occur because of the engine ABT program and/or the equipment manufacturer transition program, which are discussed in sections III.A and B. These optional programs have the potential to provide significant savings for both engine and equipment manufacturers. As a result, we consider our cost estimates to be conservative, in the sense that they likely overstate total engine and equipment costs.

In general, the final engine and equipment cost analysis is the same as that done for our proposal. We have made the following changes:

- In response to a comment, we have increased our engine research and development (R&D) costs. In the proposal, we estimated the R&D expenditure that each engine manufacturer would make to comply with the Tier 4 standards. In response to the comment, we have refined that analysis and increased our estimate of engine R&D by roughly 50 percent. We did not receive any other comments with respect to our estimates for engine R&D.

- Because the final standards for engines above 750 horsepower have changed from the proposed standards, we have made changes to the engine R&D expenditures attributed to those engines. For costing purposes, the NO_X portion of the engine R&D expenditures are no longer shared by engines above 750 horsepower. This increases NO_X R&D attributed to other engines because a significant portion of engine R&D costs are costs shared across a wide range of products. We have also reduced the engine variable costs for engines above 750 horsepower since we are no longer projecting that NO_X adsorbers will be added to them.[222] This has no impact on the engine variable costs for other engines. We have also reduced the equipment redesign costs for engines above 750 horsepower since less redesign effort is projected to accommodate only a catalyzed diesel particulate filter (CDPF). This has no impact on the redesign costs of other equipment. Lastly, we have decreased the equipment variable costs for engines above 750 horsepower for the same reason as was done for engine variable costs.
- We have changed the engine operating costs for engines above 750 horsepower to reflect a different fuel economy impact than was associated with the proposed standards and to reflect the new timing for adding the CDPF and therefore incurring the maintenance costs associated with it.
- We have included costs for additional cooling on engines adding cooled EGR systems (engines of 25 to 50 horsepower and greater than 750 horsepower). These costs include the larger radiator and/or engine cooling fan that may be required on engines expected to add cooled EGR to meet the new standards. In the proposal, we had estimated the costs for the EGR system but not the costs for additional cooling.
- We have expressed all costs in 2002 dollars for the final rule rather than the proposal's use of 2001 dollars.

We received comments on other aspects of the proposed engine and equipment cost analysis that are not reflected in the final analysis. Some of the comments were:

- Some commenters claimed that we had underestimated costs for engines under 75 horsepower, and in the 75 to 100 horsepower range. For the engines under 75 horsepower, one commenter suggested the costs were higher than EPA estimated. Please see section 5.4.1 of the Summary and Analysis of Comments for a detailed discussion of the comments and our response. In the 75 to 100 horsepower range, one commenter suggested that we were incorrect in our assumption that those engines would have electronic fuel systems in the NRT4 baseline case, maintaining the electronic fuel systems would have to be added to these engines to comply with the Tier 4 standards and, therefore, are a cost of the Tier 4 rule. From this premise, the commenter argued that the costs for 75 to 100 horsepower engines will be disproportionately high.

We disagree. In the proposal, we estimated that by 2012, engines in this power range would already have electronic fuel injection systems. This estimate was based on our engineering assessment of what technologies would be required to comply with the Tier 2 and Tier 3 emission standards, as well as technical discussions we had with engine manufacturers regarding future product plans. Therefore, the costs of these electronic fuel injection systems are not attributable to the Tier 4 rule. Our assessment at proposal is consistent with our projections in the Tier 2/3 rulemaking where we estimated costs for electronic fuel injection systems as a cost of complying with those standards. In the preamble to the proposed Tier 4 rule, we presented estimates of the penetration of various engine technologies into several power ranges, including 75 to 100 horsepower, based on engine manufacturers' 2001 model year certification data. *See* 68 FR 28386, May 23, 2003. Since then, model year certification data for 2004 are available, and these data substantiate our earlier prediction. These model year 2004 data represent implementation of the Tier 2 standards so these data illustrate the technologies engine manufacturers are using to comply with those standards. These data show that nearly 20 percent of the engines that will be produced in this power range will have electronically controlled fuel systems, while the model year 2001 data show no engines in this power range had electronic fuel systems. This dramatic increase in electronics as a result of the Tier 2 standards, let alone the Tier 3 standards, gives us confidence that our projections regarding 2012 are reasonable. Section 4.1.4 of the RIA contains a detailed discussion of this information; see also the discussions in sections II.B.4.b.i and II.B.5 above. Thus, we continue to believe that we have properly attributed costs of electronic fuel systems to the Tier 3 rule, or, put another way, that the cost of an electronic fuel system is not a cost attributable to this Tier 4 rule for engines in the 75 to 100 horsepower category. Since the cost of electronic fuel systems is the essential difference in the costs we attribute to the Tier 4 rule for these engines versus the costs the commenter would attribute, we therefore disagree with the comment and believe our estimates to be reasonable. *See also* section II.A.5 above.

- One commenter took exception to our method of amortizing fixed costs over a period of years following implementation of the new standards. The commenter suggested that we used such a method to imply to the regulated industries that they would not only recover their investments but would also make a gain on those investments. This is not the case. We use this method of amortization, briefly described here and more fully in the RIA, only to reflect the time value of money so that we can get a more accurate estimate of the cost to the companies.

The Summary and Analysis of Comments document contains the

[222] In order to avoid inconsistencies in the way our emission reductions, and cost-effectiveness estimates are calculated, our cost methodology for engines and equipment relies on the same projections of new nonroad engine growth as those used in our emissions inventory projections. Our NONROAD emission inventory model includes estimates of future engine populations that are consistent with the future engine sales used in our cost estimates. The NONROAD model inputs include an estimate of what percentage of generator sets sold in the U.S. are "mobile" and, thus, subject to the nonroad standards, and what percentage are "stationary" and not subject to the nonroad standards. These percentages vary by power category and are documented in "Nonroad Engine Population Estimates," EPA Report 420–P–02–004, December 2002. For generator sets above 750 horsepower, NONROAD assumes 100 percent are stationary and, therefore, not subject to the new nonroad standards. For generator sets under 750 horsepower, we have assumed other percentages of mobile versus stationary. During our discussions with engine manufacturers after the proposal, it became apparent not only that our estimate for generator sets above 750 horsepower may not be correct and many are indeed mobile, but also that some of our estimates for generator sets above 750 horsepower may also not be correct and many more than we estimate may indeed be mobile. If true, this increased percentage of mobile generator sets will be subject to the new nonroad standards. Unfortunately, we have not received sufficient data to make a conclusive change to the NONROAD model to include the potentially increased percentages of mobile generator sets and, therefore, for the above described purpose of maintaining consistency, we have not included their costs or their emissions reductions in our official estimates for this final rule (costs and emissions reductions for the current percentages in the NONROAD model are included in our estimates for the final rule). Instead, we present a sensitivity analysis in Chapter 8 of the RIA that includes both an estimate of the costs and emissions reductions that would result from including a higher percentage of generator sets as mobile equipment and subject to the new standards.

details of all comments and our responses.

1. Engine Cost Impacts

Estimated engine costs are broken into fixed costs (for research and development, retooling, and certification), variable costs (for new hardware and assembly time), and life-cycle operating costs. Total operating costs include the estimated incremental cost for low-sulfur diesel fuel, any expected increases in maintenance costs associated with new emission control devices, any costs associated with increased fuel consumption, and any decreases in operating cost (*i.e.*, maintenance savings) expected due to low-sulfur fuel. Cost estimates presented here represent an expected incremental cost of engines in the model year of their introduction. Costs in subsequent years will be reduced by several factors, as described below. All engine and equipment costs are presented in 2002 dollars since producer price indexes for 2003 were not available in time for use in this analysis.

a. Engine Fixed Costs

i. Engine and Emission Control Device R&D

The technologies described in Section II represent those technologies we believe will be used to comply with the Tier 4 emission standards. For many manufacturers, these technologies are part of an ongoing research and development effort geared toward compliance with the 2007 heavy-duty diesel highway emission standards. The engine manufacturers making R&D expenditures toward compliance with highway emission standards will have to undergo some additional R&D effort to transfer emission control technologies to engines they wish to sell into the nonroad market. These R&D efforts will allow engine manufacturers to develop and optimize these new technologies for maximum emission-control effectiveness with minimum negative impacts on engine performance, durability, and fuel consumption.

Many nonroad engine manufacturers are not part of the ongoing R&D effort toward compliance with highway emissions standards because they do not sell engines into the highway market. Nonetheless, these manufacturers are expected to benefit from the R&D work that has already occurred and will continue through the coming years through their contact with highway manufacturers, emission control device manufacturers, and the independent engine research laboratories conducting relevant R&D.

We project the use of several technologies for complying with the Tier 4 emission standards. We are projecting that NO_X adsorbers and catalyzed diesel particulate filters (CDPFs) will be the most likely technologies applied by industry to meet our new emissions standards for engines above 75 horsepower. The fact that these technologies are being developed for implementation in the highway market before the Tier 4 implementation dates, and the fact that engine manufacturers will have several years before implementation of the Tier 4 standards, ensures that the technologies used to comply with the nonroad standards will undergo significant development before reaching production. This ongoing development could lead to reduced costs in three ways. First, we expect research will lead to enhanced effectiveness for individual technologies, allowing manufacturers to use simpler packages of emission control technologies than we would predict given the current state of development. Similarly, we anticipate that the continuing effort to improve the emission control technologies will include innovations that allow lower-cost production. Finally, we believe that manufacturers will focus research efforts on any drawbacks, such as fuel economy impacts or maintenance costs, in an effort to minimize or overcome any potential negative effects.

We anticipate that, in order to meet the Tier 4 standards, industry will introduce a combination of primary technology upgrades. Achieving very low NO_X emissions will require basic research on NO_X exhaust emission control technologies and improvements in engine management to take advantage of the new exhaust emission control system capabilities. The manufacturers are expected to address the challenge by optimizing the engine and new exhaust emission control system to realize the best overall performance. This will entail optimizing the engine and emission control system for both emissions and fuel economy performance in light of the presence of the new exhaust emission control devices and their ability to control pollutants previously controlled only via in-cylinder means or with exhaust gas recirculation. Since most research to date with exhaust emission control technologies for nonroad applications has focused on retrofit programs which typically add an exhaust emission control device without making engine control changes, there remains room for significant improvements by taking such a systems approach. The NO_X adsorber technology in particular is expected to benefit from re-optimization of the engine management system to better match the NO_X adsorber's performance characteristics. The majority of the dollars we have estimated for research is expected to be spent on developing this synergy between the engine and NO_X exhaust emission control systems. Therefore, for engines where we project use of both a CDPF and a NO_X adsorber (*i.e.*, 75 to 750 horsepower), we have attributed two-thirds of the R&D expenditures to NO_X control, and one-third to PM control.

As we mentioned earlier, we have further refined our estimate of engine R&D costs since our proposal. We have taken these R&D costs and have broken them into two components. The first of these components estimates the corporate R&D applicable across all engine lines. The second of these estimates the engine line by engine line R&D cost. The estimates of line by line R&D correlate to power range—$1 million for under 75 horsepower engine lines, $3 million for 75 to 750 horsepower engine lines, and $6 million for above 750 horsepower engine lines. We estimated these expenditures based on the confidential information provided by the commenter and our analysis of that information. The end result is consistent with the commenter's suggested expenditure levels. We have applied these engine-line R&D estimates only where CDPFs and/or CDPF/NO_X adsorber systems are expected to be implemented (*i.e.*, this R&D is not applied for the under 75 horsepower engines in 2008 because the R&D already estimated for complying with those standards should not require the same effort to tailor it to each engine). We have also applied these estimates only for those engines without a highway counterpart (note that only 16 of a total 133 nonroad engine lines had a highway counterpart).

In the 2007 HD highway rule, we estimated that each engine manufacturer would expend $36.1 million for R&D to redesign their engines and apply catalyzed diesel particulate filters (CDPF) and NO_X adsorbers.[223] For their nonroad R&D efforts on engines where we project that compliance will require CDPFs and NO_X adsorbers (*i.e.*, 75 to 750 horsepower) and on greater than 750 horsepower engines requiring a CDPF, engine manufacturers that also sell into the highway market will incur some level of R&D effort but not at the

[223] In the 2007 rule, we estimated a value of $35 million in 1999 dollars. Here we have adjusted that value to express it in 2002 dollars.

level incurred for the highway rule. In many cases, the engines used by highway manufacturers in nonroad products are based on the same engine platform as those used in highway products. However, horsepower and torque characteristics are often different so some effort will have to be expended to accommodate those differences. For these manufacturers, we have estimated that they will incur an average R&D expense of $3.6 million [224] not including the nonroad engine line R&D noted above. This $3.6 million R&D expense will allow for the transfer of R&D knowledge from their highway experience to their nonroad engine product line. For the reasons stated above, two-thirds of this R&D is attributed to NO_X control and one-third to PM control for 75 to 750 horsepower engines; for engines above 750 horsepower, all of this R&D is attributed to PM control.

For those manufacturers that sell larger engines only into the nonroad market, and where we project those engines will add a CDPF and a NO_X adsorber (75 to 750 horsepower) or a CDPF-only (above 750 horsepower), we believe that they will incur an R&D expense nearing that incurred by highway manufacturers for the highway rule although not quite at the same level. Nonroad manufacturers will be able to learn from the R&D efforts already underway for both the highway rule and for the Tier 2 light-duty highway rule (65 FR 6698, February 10, 2000). This learning could be done via seminars, conferences, and contact with highway manufacturers, emission control device manufacturers, and the independent engine research laboratories conducting relevant R&D. Therefore, for these manufacturers, we have estimated an average expenditure of $25.3 million [225] not including the nonroad engine line R&D noted above. This lower number—$25.3 million versus $36.1 million in the highway rule—reflects the transfer of knowledge to nonroad manufacturers that will occur from the many stakeholders in the diesel industry. Two-thirds of this R&D is attributed to NO_X control and one-third to PM control.

Note that the $3.6 million and $25.3 million estimates represent our estimate of the average R&D expected by manufacturers to gain knowledge about the anticipated emission control devices. These estimates will be different for each manufacturer—some higher, some lower—depending on product mix and the number of engine lines in their product line.

For those engine manufacturers selling smaller engines that we project will add a CDPF-only (*i.e.*, 25 to 75 horsepower engines in 2013), we have estimated that the average R&D they will incur will be roughly one-third that incurred by manufacturers conducting CDPF/NO_X adsorber R&D. We believe this is a good estimate because CDPF technology is further along in its development than is NO_X adsorber technology and, therefore, a 50/50 split is not appropriate. Using this estimate, the R&D incurred by manufacturers that already have been selling any engines into both the highway and the nonroad markets will be $1.2 million not including their nonroad engine line R&D, and the R&D for manufacturers selling engines into only the nonroad market will be roughly $8.3 million [226] not including their nonroad engine line R&D. All of this R&D is attributed to PM control.

For those engine manufacturers selling engines that we project will add only a DOC or make some engine-out modifications (*i.e.*, engines under 75 horsepower in 2008), we have estimated that the average R&D they will incur will be roughly one-half the amount estimated for their CDPF-only R&D. Using this estimate, the R&D incurred by manufacturers selling any engines into both the highway and nonroad markets will be roughly $600,000, and the R&D for manufacturers selling engines into only the nonroad market will be roughly $4.2 million.[227] All of this R&D is attributed to PM control.

We have assumed that all R&D expenditures occur over a five year span preceding the first year any emission control device is introduced into the market. There is one exception to this assumption in that the expenditures for DOC-only R&D are assumed to occur over the four year span between the final rule and the 2008 standards. Where a phase-in exists (*e.g.*, for NO_X standards on 75 to 750 horsepower engines), expenditures are assumed to occur over the five year span preceding the first year NO_X adsorbers will be introduced, and then to continue during the phase-in years. The expenditures will be incurred in a manner consistent with the phase-in of the standard. All R&D expenditures are then recovered by the engine manufacturer over an identical time span following the introduction of the technology, with the exception that expenditures for DOC-only R&D are recovered over a five year span rather than a four year span. We assume an opportunity cost of capital of seven percent for all R&D. We have apportioned these R&D costs across all engines that are expected to use these technologies, including those sold in other countries or regions that are expected to have similar standards. We have estimated the fraction of the U.S. sales to this total sales at 42 percent. Therefore, we have attributed this amount to U.S. sales. Note that all engine R&D costs for engines under 25 horsepower have been attributed to U.S. sales since other countries are not expected to have similar standards on these engines.

Using this methodology, we have estimated the total R&D expenditures attributable to the new standards at $323 million with $206 million spent on corporate R&D and $118 million spent on engine line R&D. For comparison, our proposal estimated $199 million for basic R&D and none for engine line R&D. The amount for corporate R&D is higher here solely due to the change to 2002 dollars.

ii. Engine-Related Tooling Costs

Once engines are ready for production, new tooling will be required to accommodate the assembly of the new engines. We have indicated below where our tooling cost estimates have changed from the proposal. In the 2007 highway rule, we estimated approximately $1.65 million per engine line for tooling costs associated with CDPF/NO_X adsorber systems.[228] For the nonroad Tier 4 standards, we have estimated that nonroad-only manufacturers will incur the same $1.65 million per engine line requiring a CDPF/NO_X adsorber system and that these costs will be split evenly between NO_X control and PM control. For those systems requiring only a CDPF, we have estimated one-half that amount, or $825,000 per engine line. For those systems requiring only a DOC or some engine-out modifications, we have applied a one-half factor again, or $412,500 per engine line. Tooling costs for CDPF-only and for DOC engines are attributed solely to PM control. None of these estimates have changed since our proposal, with the exception of being

[224] In the proposal, we estimated a value of $3.5 million in 1999 dollars. Here we have adjusted that value to express it in 2002 dollars.

[225] In the proposal, we estimated a value of $24.5 million in 1999 dollars. Here we have adjusted that value to express it in 2002 dollars.

[226] In the proposal, we estimated values of $1.2 million and $8 million in 1999 dollars. Here we have adjusted those values to express them in 2002 dollars.

[227] In the proposal, we estimated values of $600,000 and $4 million in 1999 dollars. Here we have adjusted those values to express them in 2002 dollars.

[228] In the 2007 rule, we estimated a value of $1.6 million in 1999 dollars. Here we have adjusted that value to express it in 2002 dollars.

expressed in 2002 dollars. We received no comments on our tooling cost estimates.

For those manufacturers selling into both the highway and nonroad markets, we have estimated one-half the baseline tooling cost, or $825,000, for those engine lines requiring a CDPF/NO_X adsorber system. We believe this is reasonable since many nonroad engines are produced on the same engine line with their highway counterparts. For such lines, we believe very little to no tooling costs will be incurred. For engine lines without a highway counterpart, something approaching the $1.65 million tooling cost is applicable. For this analysis, we have assumed a 50/50 split of engine product lines for highway manufacturers and, therefore, a 50 percent factor applied to the $1.65 million baseline. These tooling costs will be split evenly between NO_X control and PM control. For engine lines under 75 horsepower and above 750 horsepower, we have used the same tooling costs as the nonroad-only manufacturers because these engines tend not to have a highway counterpart. Therefore, for those engine lines requiring only a CDPF (*i.e.*, those between 25 and 75 horsepower and those above 750 horsepower), we have estimated a tooling cost of $825,000. Note that this is a change from the proposal for engines above 750 horsepower; the proposal used the full $1.65 million since both a CDPF and a NO_X adsorber were being projected. The tooling costs for DOC and/or engine-out engine lines has also been estimated to be $412,500. Tooling costs for CDPF-only and for DOC engines are attributed solely to PM control. With the exception of the greater than 750 horsepower change, none of these tooling estimates have changed since our proposal, with the exception of being expressed in 2002 dollars.

We expect engines in the 25 to 50 horsepower range to apply EGR systems to meet the Tier 4 NO_X standards for 2013. For these engines, we have included an additional tooling cost of $41,300 per engine line, consistent with the EGR-related tooling cost estimated for 50–100 horsepower engines in our Tier 2/3 rulemaking. The EGR tooling costs are applied equally to all engine lines in that horsepower range regardless of the markets into which the manufacturer sells. We have applied this tooling cost equally because engines in this horsepower range tend not to have highway counterparts. Tooling costs for EGR systems are attributed solely to NO_X control.

We have also estimated some tooling costs for engines above 750 horsepower to meet the 2011 standards. We have estimated this amount at ten times the amount for 25 to 50 horsepower engines, or $413,000 per engine line. This cost was not in the proposal since NO_X adsorbers were being projected for engines above 750 horsepower. We have applied this tooling to all engine lines above 750 horsepower, regardless of what markets into which a manufacturer sells, since such engines clearly have no highway counterpart. For the purpose of allocating costs, we have attributed this cost entirely to NO_X control. Note that there is a new 2011 PM standard for engines above 750 horsepower. However, we believe that PM standard could be met via engine-out control which would result in no new tooling costs associated with that standard.

We have applied all the above tooling costs to all manufacturers that appear to actually make engines. We have not eliminated joint venture manufacturers because these manufacturers will still need to invest in tooling to make the engines even if they do not conduct any R&D. We have assumed that all tooling costs are incurred one year in advance of the new standard and are recovered over a five year period following implementation of the new standard; all tooling costs include a capital opportunity cost of seven percent. As done for R&D costs, we have attributed a portion of the tooling costs to U.S. sales and a portion to sales in other countries expected to have similar levels of emission control. Note that all engine tooling costs for under 25 horsepower engines have been attributed to U.S. sales since other countries are not expected to have similar standards on these engines. More information is contained in chapter 6 of the RIA.

Using this methodology, we estimate the total tooling expenditures attributable to the new Tier 4 standards at $74 million. For comparison, our proposal estimated $67 million. The higher value here is a result of: Expressing values in 2002 dollars rather than 2001 dollars; attributing all under 25 horsepower tooling costs to U.S. sales while the proposal attributed 42 percent of those costs to U.S. sales; and, above 750 horsepower tooling is slightly higher because of the proposal's phase-in (50/50/50/100) of one set of standards while the final rule has two sets of standards.

iii. Engine Certification Costs

The comments we received with respect to our estimated certification costs noted that we had underestimated costs associated with new test procedures, especially transient testing for engines above 750 horsepower. For the final rule, we have tripled the costs associated with new test procedures. Because we are not finalizing transient test procedures for engines above 750 horsepower, comments about the cost of these engines certifying using the transient test are now moot.

Manufacturers will incur more than the normal level of certification costs during the first few years of implementation because engines will need to be certified to the new emission standards using new test procedures (at least in some instances). Consistent with our recent standard setting regulations, we have estimated engine certification costs at $60,000 per new engine certification to cover existing testing and administrative costs.[229] The $60,000 certification cost per engine family was used for 25 to 75 horsepower engines certifying to the 2008 standards. For 25 to 75 horsepower engines certifying to the 2013 standards, and for 75 to 750 horsepower engines certifying to their new standards, we have added costs to cover the new test procedures for nonroad diesel engines (*e.g.*, the transient test, the NTE);[230] these costs are estimated at $31,500 per engine family.[231] For engines under 25 horsepower, we have assumed (for cost purposes) that all engines will certify to the transient test and the NTE in 2008. We believe manufacturers may choose to do this rather than certifying all engines again in 2013 when the transient test and NTE requirements actually begin for those engines. This assumption results in higher certification costs in 2008 than if these engines certified only to the steady-state standard. However, we believe manufacturers may choose to do this because it would avoid the need to

[229] In the proposal we added a certification fee to this cost. In the final rule we have not included the certification fee because that cost will be accounted for in the certification fees rulemaking (see 67 FR 51402 for the proposed rule). Including in the proposal was essentially double counting that fee. Similarly, if we were to include it in this final rule, we would be double counting that fee.

[230] Note that the transport refrigeration unit (TRU) test cycle is an optional duty cycle for steady-state certification testing specifically tailored to the operation of TRU engines. Likewise, the ramped modal cycles are available test cycles that can be used to replace existing steady-state test requirements for nonroad constant-speed engines, generally. Manufacturers of these engines who opt to use one of these test cycles would incur no new costs above those estimated here and may incur less cost.

[231] Note that the proposal incorrectly used a value of $10,500 for costs associated with the new test procedures. Here, we have corrected this error by using a value of $31,500. Note also that the proposal erroneously did not include certification costs associated with transient testing and the NTE for engines under 25 horsepower. We have corrected that error in the final analysis.

recertify all engines under 25 horsepower again in 2013. These certification costs—whether it be the $60,000 or the $91,500 per engine family—apply equally to all engine families for all manufacturers regardless of into what markets the manufacturer sells. For engines above 750 horsepower, the certification costs used were $87,000 per family since these engines will not be certifying over the new transient test procedure. We have applied these certification costs to all U.S. sold engine families and then spread the total over U.S. sales. In other words, we have not presumed that certification conducted for U.S. engines would fulfill the certification requirements of other countries and have, therefore, not spread total costs over engine sales outside the U.S.

Applying these costs to each of the 665 engine families as they are certified to a new emissions standard results in total costs of $91 million expended during implementation of the Tier 4 standards. These costs are attributed to NO_X and PM control consistent with the phase-in of the new emissions standards—where new NO_X and PM standards are introduced together, the certification costs are split evenly; where only a new PM standard is introduced, the certification costs are attributed to PM only; where a NO_X phase-in becomes 100 percent in a year after full implementation of a PM standard, the certification costs are attributed to NO_X only. All certification costs are assumed to occur one year prior to the new emission standard and are then recovered over a five year period following compliance with the new standard; all certification costs include a capital opportunity cost of seven percent. For comparison, our proposal estimated certification costs at $72 million. The increase here is a result of using a higher cost associated with the new test procedures than was used in the proposal.

We also received comment that we should estimate certification costs based on use of the ABT program rather than based on the phase-in. Doing this would result in higher certification costs because all engine families would be certified in year one of the phase-in and all families would again be certified in the final year of the phase-in. In contrast, since we have based certification costs on the phase-in, all engine families are certified in year one (PM standards have no phase-in) and only half are again certified in the final year (the 50 percent not meeting the new NO_X standard in year one). We have chosen not to estimate certification or any costs based on use of the ABT program (or the TPEM program) since it is so difficult to predict how this program will be used. Furthermore, we must remain consistent throughout our cost analysis so that, if we estimated certification costs based on use of the ABT program, we should also base engine variable costs and equipment variable costs on use of the ABT program. Doing so, we believe, would decrease engine variable costs since that is the primary reason manufacturers choose to make use of the ABT program. Since engine variable costs, as discussed below, are a much greater fraction of the overall program costs, we believe that we are being conservative by generating our costs based on use of the phase-in. Therefore, we believe that use of the ABT program (and the TPEM program) will provide substantial net savings to industry even though widespread use of ABT might cause certification costs to be higher.

b. Engine Variable Costs

This section summarizes the detailed analysis presented in chapter 6 of the RIA. For our analysis, we have used the 2002 annual average costs for platinum and rhodium (the two platinum group metals (PGMs) we expect will be used) because we believe they represent a better estimate of the cost for PGM than other metrics. In the RIA, we present a cost sensitivity that estimates the recovery value of precious metals returned to the open market upon retirement of an aftertreatment device. We present that analysis to gauge the true social cost of these devices when new.

We have not made any changes to our engine variable costs as a result of public comments. Some commenters (engine manufacturers) claimed that we had underestimated these costs but did not provide any detailed information about where they believed we had erred or what they believed the costs should be. Other commenters (emission control device manufacturers) claimed that we had done a fair job with our estimates. Some commenters (equipment manufacturers) claimed that our assumptions with respect to baseline engine configurations were not accurate. However, as discussed earlier, based on our own engineering judgement and the positive comments of the engine manufacturers—who we consider a better source for such information than equipment manufacturers since engine manufacturers are the directly affected entities—we have maintained our original assumptions for baseline engine configurations. Further, our assumed Tier 4 baseline engine configurations are consistent with our assumed compliant technology packages for T2/3, and those packages included the things equipment manufacturers are claiming will not be present in the Tier 4 baseline. As a result, we have already considered the costs associated with reaching our Tier 4 baseline engine configurations in the context of the T2/3 rule.

We have made changes to engine variable costs to remain consistent with the final program—*i.e.*, we have changed our greater than 750 horsepower cost estimates since the final standards differ from those that were proposed. We have also changed the costs by expressing them in 2002 dollars rather than 2001 dollars.[232]

i. NO_X Adsorber System Costs

The NO_X adsorber system that we are anticipating will be used to comply with Tier 4 engine standards will be the same as that used for highway applications. In order for the NO_X adsorber to function properly, a systems approach that includes a reductant metering system and control of engine A/F ratio is also necessary. Many of the new air handling and electronic system technologies developed in order to meet the Tier 2/3 nonroad engine standards can be applied to accomplish the NO_X adsorber control functions as well (these costs were accounted for in our T2/3 rule). Some additional hardware for exhaust NO_X or O_2 sensing and for fuel metering will likely be required. The cost estimates include a DOC for clean-up of hydrocarbon emissions that occur during NO_X adsorber regeneration events. We have also estimated that warranty costs will increase due to the application of this new hardware. Chapter 6 of the RIA contains the details for how we estimated costs associated with the new NO_X control technologies required to meet the Tier 4 emission standards. These costs are estimated to increase engine costs by roughly $670 in the near-term for a 150 horsepower engine, and $2,040 in the near-term for a 500 horsepower engine. In the long-term, we estimate these costs to be $550 and $1,650 for the 150 horsepower and 500 horsepower engines, respectively. These costs may differ slightly from the proposal due to the adjustments to 2002 dollars. Note that we have estimated costs for all engines in all horsepower

[232] Note that the change to 2002 dollars had different effects on different pieces of hardware. We have used two different PPI adjustments in the analysis: one for motor vehicle catalytic converters which was used to adjust costs for DOCs, NO_X adsorbers, and CDPFs; and another for motor vehicle parts and accessories which was used for all other pieces of hardware. The former of these adjustments actually caused costs to decrease relative to the proposal while the latter caused costs to increase slightly.

ranges, and these estimates are presented in detail in the RIA. Throughout this discussion of engine and equipment costs, we present costs for a 150 and a 500 horsepower engine for illustrative purposes.

ii. Catalyzed Diesel Particulate Filter (CDPF) Costs

CDPFs can be made from a wide range of filter materials including wire mesh, sintered metals, fibrous media, or ceramic extrusions. The most common material used for CDPFs for heavy-duty diesel engines is cordierite. Here we have based our cost estimates on the use of silicon carbide (SiC) even though it is more expensive than other filter materials.[233] We estimate that the CDPF systems will add $760 to engine costs in the near-team for a 150 horsepower engine and $2,710 in the near-term for a 500 horsepower engine. In the long-term, we estimate these CDPF system costs to be $580 and $2,070 for the 150 horsepower and the 500 horsepower engines, respectively. These costs may differ slightly from the proposal due to the adjustments to 2002 dollars.

iii. CDPF Regeneration System Costs

Application of CDPFs in nonroad applications may present challenges beyond those of highway applications. For this reason, we anticipate that some additional hardware beyond the diesel particulate filter itself may be required to ensure that CDPF regeneration occurs. For some engines this may be new fuel control strategies that force regeneration under some circumstances, while in other engines it might involve an exhaust system fuel injector to inject fuel upstream of the CDPF to provide necessary heat for regeneration under some operating conditions. We estimate the near-term costs of a CDPF regeneration system to be $200 for a 150 horsepower engine and $330 for a 500 horsepower engine. In the long-term, we estimate these costs at $150 and $250, respectively. These costs may differ slightly from the proposal due to the adjustments to 2002 dollars.

iv. Closed-Crankcase Ventilation System (CCV) Costs

Today's final rule eliminates the exemption that allows turbo-charged nonroad diesel engines to vent crankcase gases directly to the environment. Such engines are said to have an open crankcase system. We project that this requirement to close the crankcase on turbo-charged engines will force manufacturers to rely on engineered closed crankcase ventilation systems that filter oil from the blow-by gases prior to routing them into either the engine intake or the exhaust system upstream of the CDPF. We have estimated the initial cost of these systems to be roughly $30 for low horsepower engines and up to $90 for very high horsepower engines. These costs are incurred only by turbo-charged engines because today's naturally aspirated engines already have CCV systems. These costs may differ slightly from the proposal due to the adjustments to 2002 dollars.

v. Variable Costs for Engines Below 75 Horsepower and Above 750 Horsepower

The Tier 4 program includes standards for engines under 25 horsepower that begin in 2008, and two sets of standards for 25 to 75 horsepower engines—one set that begins in 2008 and another that begins in 2013.[234] The 2008 standards for all engines under 75 horsepower are of similar stringency and are expected to result in use of similar technologies (*i.e.*, the possible addition of a DOC). The 2013 standards for 25 to 75 horsepower engines are considerably more stringent than the 2008 standards and are expected to force the addition of a CDPF along with some other engine hardware to enable the proper functioning of that new technology. More detail on the mix of technologies expected for all engines under 75 horsepower is presented in section II.B.4 and 5. As discussed there, if changes are needed to comply, we expect manufacturers to comply with the 2008 standards through either engine-out improvements or through the addition of a DOC. From a cost perspective, we have projected that engines will add a DOC. Presumably, the manufacturer will choose the least costly approach that provides the necessary reduction. If engine-out modifications are less costly than a DOC, our estimate here is conservative. If the DOC proves to be less costly, then our estimate is representative of what most manufacturers will do. Therefore, we have assumed that, beginning in 2008, all engines below 75 horsepower add a DOC. Note that this estimate is made more conservative since we have assumed this cost for all engines when, in fact, some engines below 75 horsepower currently meet the Tier 4 PM standard (for 2008) and will not, therefore, incur any incremental costs to meet it. We have estimated this added hardware to result in an increased engine cost of $143 in the near-term and $136 in the long-term for a 30 horsepower engine. These costs may differ slightly from the proposal due to the adjustments to 2002 dollars.

We have also projected that some engines in the 25 to 75 horsepower range will have to upgrade their fuel systems to accommodate the CDPF. We have estimated the incremental costs for these fuel systems at roughly $870 for a three cylinder engine in the 25–50 horsepower range, and around $450 for a four cylinder engine in the 50–75 horsepower range. This difference reflects a different base fuel system, with the smaller engines assumed to have mechanical fuel systems and the larger engines assumed to already be electronic. The electronic systems will incur lower costs because they already have the control unit and electronic fuel pump. Also, we have assumed these fuel changes will occur for only direct injection (DI) engines; indirect injection engines (IDI) are assumed to remain IDI but to add more hardware as part of their CDPF regeneration system to ensure proper regeneration under all operating conditions. Such a regeneration system, described above, is expected to cost roughly twice that expected for DI engines, or around $320 for a 30 horsepower IDI engine versus $160 for a DI engine. These costs may differ slightly from the proposal due to the adjustments to 2002 dollars.

We have also projected that engines in the 25–50 horsepower range will add cooled EGR to comply with their new NO_X standard in 2013. Additionally, we have estimated, for cost purposes, that engines above 750 horsepower will add cooled EGR to comply with their new NO_X standard in 2011. This represents a conservative estimate since we do not necessarily anticipate that cooled EGR will be applied to all, if any, engines above 750 horsepower. Nonetheless, we do expect some changes to be made (most probably some form of engine-out emission control) and, consistent with our approach to costing DOCs for engines below 75 horsepower in 2008, we have conservatively costed cooled EGR for engines above 750 horsepower in 2011. We have estimated that the EGR system will add $100 in the near-term and $70 in the long-term to the cost of a 30 horsepower engine, and $550 and $420, respectively, for engines above 750 horsepower. These costs may differ slightly from the proposal due to

[233] This is particularly true with respect to engines above 750 horsepower where we believe that manufacturers may in fact use a wire mesh substrate rather than the SiC substrate we have costed and, indeed, we have based the level of the 2015 PM standard on this use of wire mesh substrates (*see* section II.B.3.b). We have chosen to remain conservative in our cost estimates by assuming use of a SiC substrate for all engines.

[234] We refer here to PM standards. There also is a NO_X+NMHC standard for 25–50 horsepower engines that takes effect in 2013 and is equivalent to the Tier 3 NO_X+NMHC standard for 50–75 horsepower engines (see section II.A).

the adjustments to 2002 dollars. To these costs, we have added costs associated with additional cooling that may be needed to reject the heat generated by the cooled EGR system or other in-cylinder technologies. These costs were not included in the proposal. Such additional cooling might take the form of a larger radiator and/or a larger or more powerful cooling fan. Based on cost estimates from our Nonconformance Penalty rule (67 FR 51464), we have estimated that the costs associated with additional cooling will add $40 in the near-term and $30 in the long-term to the cost of a 30 horsepower engine, and $710 in the near-term and $560 in the long-term for engine above 750 horsepower. Note that we are also projecting use of a CDPF for engines above 750 horsepower, as was discussed above.

We believe there are factors that will cause variable hardware costs to decrease over time, making it appropriate to distinguish between near-term and long-term costs. Research in the costs of manufacturing has consistently shown that as manufacturers gain experience in production, they are able to apply innovations to simplify machining and assembly operations, use lower cost materials, and reduce the number or complexity of component parts.[235] Our analysis, as described in more detail in the RIA, incorporates the effects of this learning curve by projecting that the variable costs of producing the low-emitting engines decreases by 20 percent starting with the third year of production. For this analysis, we have assumed a baseline that represents such learning already having occurred once due to the 2007 highway rule (*i.e.*, a 20 percent reduction in emission control device costs is reflected in our near-term costs). We have then applied a single learning step from that point in this analysis. Additionally, manufacturers are expected to apply ongoing research to make emission controls more effective and to have lower operating costs over time. However, because of the uncertainty involved in forecasting the results of this research, we conservatively have not accounted for it in this analysis.

c. Engine Operating Costs

We are projecting that a variety of new technologies will be introduced to enable nonroad engines to meet the new Tier 4 emissions standards. Primary among these are advanced emission control technologies and low-sulfur diesel fuel. The technology enabling benefits of low-sulfur diesel fuel are described in Section II, and the incremental cost for low-sulfur fuel is described in section VI.A. The new emission control technologies are themselves expected to introduce additional operating costs in the form of increased fuel consumption and increased maintenance demands. Operating costs are estimated in the RIA over the life of the engine and are expressed in terms of cents/gallon of fuel consumed. In section VI.C.3, we present these lifetime operating costs as a net present value (NPV) in 2002 dollars for several example pieces of equipment.

Total operating cost estimates include the following elements: the change in maintenance costs associated with applying new emission controls to the engines; the change in maintenance costs associated with low sulfur fuel such as extended oil change intervals; the change in fuel costs associated with the incrementally higher costs for low sulfur fuel, and the change in fuel costs due to any fuel consumption impacts associated with applying new emission controls to the engines. This latter cost is attributed to the CDPF and its need for periodic regeneration which we estimate may result in a one percent fuel consumption increase where a NO_X adsorber is also applied, or a two percent fuel consumption increase where no NO_X adsorber is applied (refer to chapter 6, section 6.2.3.3 of the RIA). Maintenance costs associated with the new emission controls on the engines are expected to increase since these devices represent new hardware and, therefore, new maintenance demands. For CDPF maintenance, we have used a maintenance interval of 3,000 hours for smaller engines and 4,500 hours for larger engines and a cost of $65 through $260 for each maintenance event. For closed-crankcase ventilation (CCV) systems, we have used a maintenance interval of 675 hours for all engines and a cost per maintenance event of $8 to $48 for small to large engines. Offsetting these maintenance cost increases will be a savings due to an expected increase in oil change intervals because low sulfur fuel will be far less corrosive than is current nonroad diesel fuel. Less corrosion will mean a slower acidification rate (*i.e.*, less degradation) of the engine lubricating oil and, therefore, more operating hours between needed oil changes. As discussed in section VI.B, the use of 15 ppm sulfur fuel can extend oil change intervals by as much as 35 percent for both new and existing nonroad engines and equipment. We have used a 35 percent increase in oil change interval along with costs per oil change of $70 through $400 to arrive at estimated savings associated with increased oil change intervals.

These operating costs are expressed as a cent/gallon cost (or savings). As a result, operating costs are directly proportional to the amount of fuel consumed by the engine. We have estimated these operating costs—fuel-related refining and distribution costs, maintenance related costs, and fuel economy impacts—to be 5.4 cents/gallon for a 150 horsepower engine and 6.5 cents/gallon for a 500 horsepower engine. More detail on operating costs can be found in Chapter 6 of the RIA.

The existing fleet will also benefit from lower maintenance costs due to the use of low sulfur diesel fuel. The operating costs for the existing fleet are discussed in section VI.B. We did receive comments with respect to our oil change maintenance savings estimates. These comments were address in section VI.B. We received no comments on our CDPF and CCV maintenance costs or our CDPF regeneration costs.

2. Equipment Cost Impacts

In addition to the costs directly associated with engines that incorporate new emission controls to meet new standards, costs will increase due to the need to redesign the nonroad equipment in which these engines are used. Such redesigns will probably be necessary due to the expected addition of new emission control systems, but could also occur if the engine has a different shape or heat rejection rate, or is no longer made available in the configuration previously used. We have accounted for these potential changes in establishing the lead time for the Tier 4 emissions standards. The transition flexibility provisions for equipment manufacturers that are included in this final rule are an element of that lead time. These flexibility provisions are described in detail in section III.B.

In assessing the economic impact of the new emission standards, EPA has made a best estimate of the modifications to equipment that relate to packaging (installing engines in equipment engine compartments). The incremental costs for new equipment will be comprised of fixed costs (for redesign to accommodate new emission control devices) and variable costs (for new equipment hardware to affix the new emission control devices and for labor to install those emission control devices). Note that the fixed costs do not

[235] For example, *see*, "Learning Curves in Manufacturing," Linda Argote and Dennis Epple, Science, February 23, 1990, Vol. 247, pp. 920–924.

include certification costs because the equipment is not certified to emission standards. The engine is certified by the engine manufacturer; therefore, the related certification costs are counted as an engine fixed cost. We have also attributed all changes in operating costs (*e.g.*, additional maintenance) to the cost estimates for engines. Included in section VI.C.3 is a discussion of several example pieces of equipment (*e.g.*, skid/steer loader, dozer, etc.) and the costs we have estimated for these specific example pieces of equipment. Full details of our equipment cost analysis can be found in chapter 6 of the RIA. All costs are presented in 2002 dollars.

We have made only limited changes relative to the proposal with respect to our estimated equipment costs, as discussed below. We did receive comment that we underestimated costs for equipment redesign and for markups on equipment variable costs. The commenters making these claims relative to equipment redesign costs tended to be those that have relative high equipment sales volumes. Such manufacturers tend to expend levels higher than we estimated in our proposal for equipment redesign because they sell into highly competitive markets and they can spread costs over many units. However, some equipment manufacturers we have met with, most notably those with small sales volumes, do not appear to expend nearly the level we estimated in the proposal. These manufacturers tend to sell into markets with few competitors, produce machines by hand, and expend less redesign effort relative to a high sales volume manufacturer.[236] Our goal in the proposal was to estimate the redesign costs spent by industry (*i.e.*, the average cost per piece of equipment multiplied by all equipment resulting in an estimated total industry cost), rather than estimating the maximum cost to be spent by any particular manufacturer. As a result, our equipment redesign estimates per model may be too low for some manufacturers, but they are also too high for others. We believe this cost methodology provides as accurate an estimate as can be made. We have used the same methodology for the final cost estimates presented here.

As for the comments with respect to equipment variable costs, we did indeed include a markup of 29 percent and disagree with the commenter that a two-to-one markup would be more appropriate. Such a high markup on equipment variable costs is not sustainable in a competitive market, at least on average, and the commenter provided no data nor study that supported the comment.

We have made minor changes to the proposed numbers to express them in 2002 dollars and to reflect where the program has changed (*i.e.*, greater than 750 horsepower mobile machines). We have also attributed all under 25 horsepower redesign costs to U.S. sales since we do not expect other countries to have similar emission standards for these engines/equipment. Lastly, we have corrected some minor errors made in the proposal in determining motive versus non-motive models and determining the number of unique equipment models needing redesign. We now estimate that a total of over 4,500 equipment models will be redesigned as compared to the proposal's estimate of just over 4,100 equipment models. Further discussion of these changes can be found in Chapter 6 of the RIA.

a. Equipment Fixed Costs

As we noted in the proposal, the most significant changes anticipated for equipment redesign are changes to accommodate the physical changes to engines, especially for those engines that add PM traps and NO_X adsorbers. The costs for engine development and the emission control devices are included as costs to the engines, as described above. Equipment manufacturers must still incur the effort and expense of integrating the engine and emissions control devices into the piece of equipment. Therefore, we have allocated extensive engineering time for this effort.

The costs we have estimated are based on engine power and whether an application is non-motive (*e.g.*, a generator set) or motive (*e.g.*, a skid steer loader). The designs we have considered to be non-motive are those that lack a propulsion system. In addition, the new emission standards for engines rated under 25 horsepower and the 2008 standards for 25–75 horsepower engines are projected to require no significant equipment redesign beyond that done to accommodate the Tier 2 standards. As explained earlier, we expect that these engines will comply with the new Tier 4 standards through either engine modifications to reduce engine-out emissions or through the addition of a DOC. We have projected that engine modifications will not affect the outer dimensions of the engine and that a DOC will replace the existing muffler. Therefore, either approach taken by the engine manufacturer should have limited to no impact on the equipment design. Nonetheless, we have conservatively estimated their redesign costs at $53,100 per model.[237]

A number of equipment manufacturers have shared detailed information with us regarding the investments made for Nonroad Tier 2 equipment redesign efforts, as well as redesign estimates for significant changes such as installing a new engine design. These estimates range from approximately $53,100 for some lower powered equipment models to well over $1 million for high horsepower equipment with very challenging design constraints. We believe that the equipment redesign efforts undertaken for the T2/3 are representative of the effort that will be required for Tier 4 because the changes needed are the same in nature—increasing available space within the machine to accommodate new hardware. We have based our Tier 4 estimates, in part, on that industry input and have estimated that equipment redesign costs will range from $53,100 per model for 25 horsepower equipment up to $796,500 per model for 300 horsepower equipment and above. For mobile machines greater than 750 horsepower, we have used a new redesign cost of $106,000 associated with the 2011 standards which is consistent in scale with the estimate used for 25 to 50 horsepower equipment that add both EGR and a CDPF in the 2013 timeframe. This estimate was not in the proposal. For this larger equipment, we have continued with an estimate of $796,500 associated with the 2015 standards even though we project no need to accommodate a NO_X adsorber. We have attributed only a portion of the equipment redesign costs to U.S. sales in a manner consistent with that taken for engine R&D costs and engine tooling costs. In addition, we expect manufacturers to incur some fixed costs to update service and operation manuals to address the maintenance demands of new emission control technologies and the new oil service intervals; we estimate these service manual updates to cost between $2,660 and $10,620 per equipment model.

These equipment fixed costs (redesign and manual updates) were then allocated appropriately to each new model to arrive at a total equipment fixed cost of $828 million. We have assumed that these costs will be

[236] "Meeting between Staff of Eagle Crusher Company, Inc., and EPA," memorandum from Todd Sherwood to Air Docket A–2001–28, Docket Item IV–E–40, EDOCKET OAR–2003–0012–0868, March 16, 2004.

[237] Note that the equipment redesign estimates, and all other equipment related costs, have been adjusted from the NPRM to express them in 2002 dollars.

recovered over a ten year period with a seven percent opportunity cost of capital. By comparison, our proposal estimated equipment fixed costs at $698 million. The costs are higher now because of the changes mentioned above—expressing costs in 2002 dollars; attributing all under 25 horsepower redesign costs to U.S. sales; and, correcting upward the number of equipment models to be redesigned.

b. Equipment Variable Costs

Equipment variable cost estimates are based on costs for additional materials to mount the new hardware (*i.e.*, brackets and bolts required to secure the aftertreatment devices) and additional sheet metal assuming that the body cladding of a piece of equipment (*i.e.*, the hood) might change to accommodate the aftertreatment system. Variable costs also include the labor required to install these new pieces of hardware. For engines above 75 horsepower—those expected to incorporate CDPF and NO_X adsorber technology—the amount of sheet metal is based on the size of the aftertreatment devices.

For equipment of 150 horsepower and 500 horsepower, respectively, we have estimated the costs to be roughly $60 to $150. Note that we have estimated costs for equipment in all horsepower ranges, and these estimates are presented in detail in the RIA. Throughout this discussion of engine and equipment costs, we present costs for a 150 and a 500 horsepower engine for illustrative purposes.

3. Overall Engine and Equipment Cost Impacts

To illustrate the engine and equipment cost impacts we are estimating for the Tier 4 standards, we have chosen several example pieces of equipment and have presented the estimated costs for them. Using these examples, we can calculate the costs for a specific piece of equipment in several horsepower ranges and better illustrate the cost impacts of the new standards. These costs along with information about each example piece of equipment are shown in table VI.C–1. Costs presented are near-term and long-term costs for the final standards to which each piece of equipment will comply. Long-term costs are only variable costs and, therefore, represent costs after all fixed costs have been recovered and all projected learning has taken place. Included in the table are estimated prices for each piece of equipment to provide some perspective on how our estimated control costs relate to existing equipment prices.

TABLE VI.C–1.—NEAR-TERM AND LONG-TERM COSTS FOR SEVERAL EXAMPLE PIECES OF EQUIPMENT [a]

($2002, for the final emission standards to which the equipment must comply)

	Gen-Set	Skid/steer loader	Backhoe	Dozer	Ag tractor	Dozer	Off-highway truck
Horsepower	9 hp	33 hp	76 hp	175 hp	250 hp	503 hp	1000 hp
Incremental Engine & Equipment Cost	$120	$790	$1,200	$2,560	$1,970	$4,140	$4,670
Long-Term	180	1,160	1,700	3,770	3,020	6,320	8,610
Near-Term.							
Estimated Equipment Price when New [b]	4,000	20,000	49,000	238,000	135,000	618,000	840,000
Incremental Operating Costs [c]	−80	70	610	2,480	2,110	7,630	20,670
Baseline Operating Costs (Fuel & Oil only) [c]	940	2,680	7,960	27,080	23,750	77,850	179,530

Notes: [a] Near-term costs include both variable costs and fixed costs; long-term costs include only variable costs and represent those costs that remain following recovery of all fixed costs. [b] "Price Database for New Nonroad Equipment," memorandum from Zuimdie Guerra to EDOCKET OAR–2003–0012–0960. [c] Present value of lifetime costs.

More detail and discussion regarding what these costs and prices mean from an economic impact perspective can be found in section VI.E.

D. Annual Costs and Cost Per Ton

One tool that can be used to assess the value of the Tier 4 standards for NRLM fuel and nonroad engines is the costs incurred per ton of emissions reduced. This analysis involves a comparison of our new program to other measures that have been or could be implemented. As summarized in this section and detailed in the RIA, the program being finalized today represents a highly cost effective mobile source control program for reducing PM, NO_X, and SO_2 emissions.

We have calculated the cost per ton of our Tier 4 program based on the net present value of all costs incurred and all emission reductions generated over a 30 year time window following implementation of the program (*i.e.*, calendar years 2007 through 2036). This approach captures all of the costs and emissions reductions from our new program including those costs incurred and emissions reductions generated by the existing fleet. The baseline for this evaluation is the existing set of fuel and engine standards (*i.e.*, unregulated NRLM fuel and the Tier 2/Tier 3 program). The 30 year time window chosen is meant to capture both the early period of the program when very few new engines that meet the new standards will be in the fleet, and the later period when essentially all engines will meet the new standards.

We have analyzed the cost per ton reduced of several different scenarios. The costs and emissions reductions of each of these scenarios are presented in detail in chapter 8 of the RIA. Here, we present information of the cost and cost effectiveness for the following two scenarios: (1) The full NRLM fuel and nonroad engine program, meaning two steps of fuel control (to 500 ppm and then to 15 ppm) for both NR and L&M fuel and all of the nonroad engine standards; and, (2) the NRLM fuel-only program, meaning two steps of fuel control (to 500 ppm and then to 15 ppm) for both NR and L&M fuel but without any new nonroad engine standards.[238] For the first of these scenarios, the discussion illustrates the costs and relative cost effectiveness of the final NRT4 program to other programs. For the second of these scenarios, the discussion illustrates the costs and cost effectiveness associated with the fuel program as if implemented as a stand alone program without new engine standards.

In sections VI.D.1 and 2, we present the cost of the full NRLM fuel and nonroad engine program and the cost per ton of PM, NO_X+NMHC, and SO_2 reductions that will be realized. The analysis presented in sections VI.D.1 and 2 represents the total Tier 4 program for nonroad diesel engines and NRLM fuel being finalized today. In sections VI.D.3 and 4, we summarize the

[238] We are not analyzing a scenario involving just the engine standards because the nonroad engine standards involving advanced emissions control technologies require the use of the 15ppm fuel.

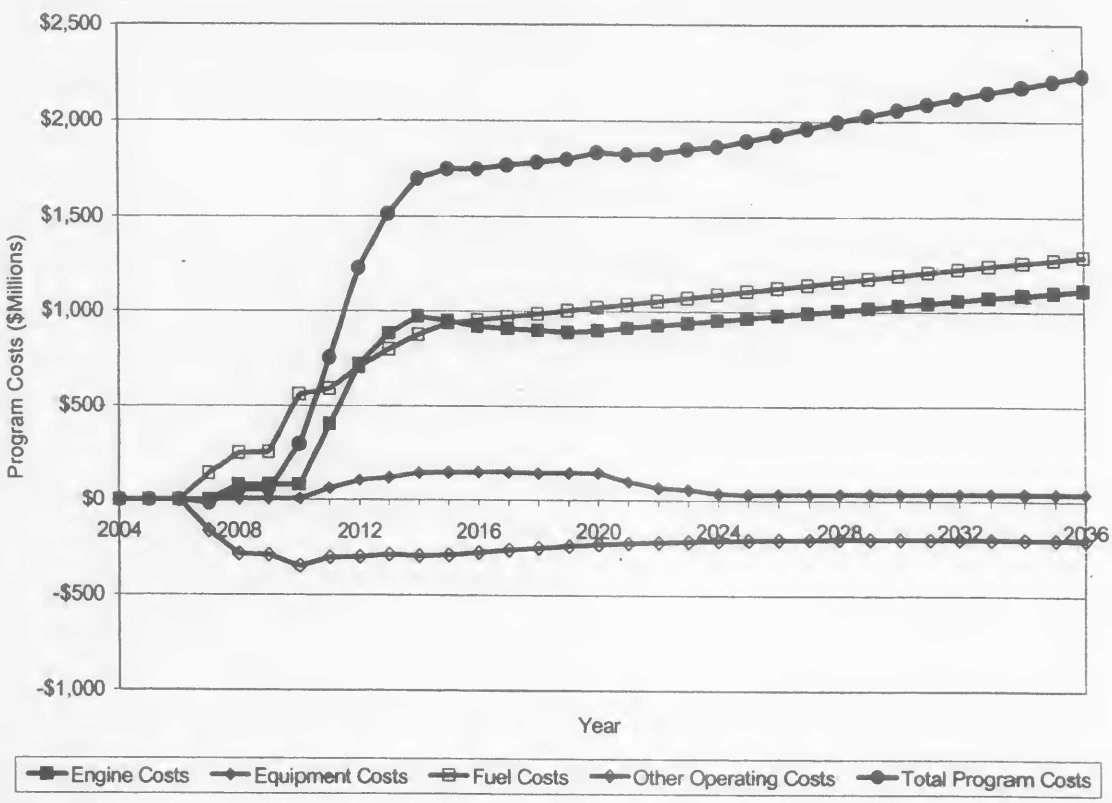
cost for the NRLM fuel-only scenario and the cost per ton of PM and SO_2 reductions that would be realized.

1. Annual Costs for the Full NRLM Fuel and Nonroad Engine Program

The costs of the full NRLM fuel and nonroad engine program include costs associated with both steps in the NRLM fuel program—the NR fuel reduction to 500 ppm sulfur in 2007 and to 15 ppm sulfur in 2010 and the L&M fuel reduction to 500 ppm sulfur in 2007 and to 15 ppm sulfur in 2012. Also included are costs for the 2008 nonroad engine standards for engines less than 75 horsepower, the 2013 standards for 25 to 75 horsepower engines, and costs for the nonroad engine standards for engines above 75 horsepower. All maintenance and operating costs are included along with maintenance savings realized by both the existing fleet (nonroad, locomotive, and marine) and the new fleet of engines complying with the Tier 4 standards.

Figure VI.D–1 presents these results. All capital costs for NRLM fuel production and nonroad engine and equipment fixed costs have been amortized at seven percent. The figure shows that total annual costs are estimated to be $50 million in the first year the new engine standards apply, increasing to a peak of $2.2 billion in 2036 as increasing numbers of engines become subject to the new nonroad standards and an ever increasing amount of NRLM fuel is consumed. The net present value of the annualized costs over the period from 2007 to 2036 is $27 billion using a 3 percent discount rate and $14 billion using a 7 percent discount rate.

Figure VI.D-1. – Annual Costs of the Full NRT4 Fuel and Engine Program



2. Cost per Ton of Emissions Reduced for the Full NRLM Fuel and Nonroad Engine Program

We have calculated the cost per ton of emissions reduced associated with the NRT4 engine and NRLM fuel program. The resultant cost per ton numbers depend on how the costs presented above are allocated to each pollutant. Therefore, we have carefully allocated costs according to the pollutants for which they are incurred. Where fuel changes occur in conjunction with new engine standards (engine standards enabled by those fuel changes), we allocate one-half of the fuel-related costs to fuel-derived emissions reductions (PM and SO_2, with one-third of that half allocated to PM and two-thirds to SO_2) and one-half to engine-derived emissions reductions (NO_X+NMHC and PM, with that half split 50/50 between each pollutant). Where fuel changes occur without new engine standards on which fuel changes are premised (*i.e.*, 500ppm NRLM fuel and 15ppm L&M fuel), we have allocated costs associated with fuel-derived emissions reductions one-third to PM and two-thirds to SO_2. We have allocated costs associated with engine-derived emissions reductions (*i.e.*, engine/equipment costs) directly to the pollutant for which the cost is incurred. These engine and equipment cost allocations are noted throughout the discussion in section VI.C, and are detailed in full in chapter 8 of the RIA.

We have calculated the costs per ton using the net present value of the annualized costs of the program through 2036 and the net present value of the annual emission reductions through 2036. We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emissions reductions in that year alone. This number represents the long-term cost per ton of emissions reduced. The cost per ton numbers include costs and emission reductions that will occur from the existing fleet (*i.e.*, those pieces of nonroad equipment that were sold into the market prior to the new emission standards). These results are shown in Table VI.D–1 using both a three percent and a seven percent social discount rate.

TABLE VI.D–1.—TOTAL FUEL AND ENGINE PROGRAM 30 YEAR AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON

($2002)

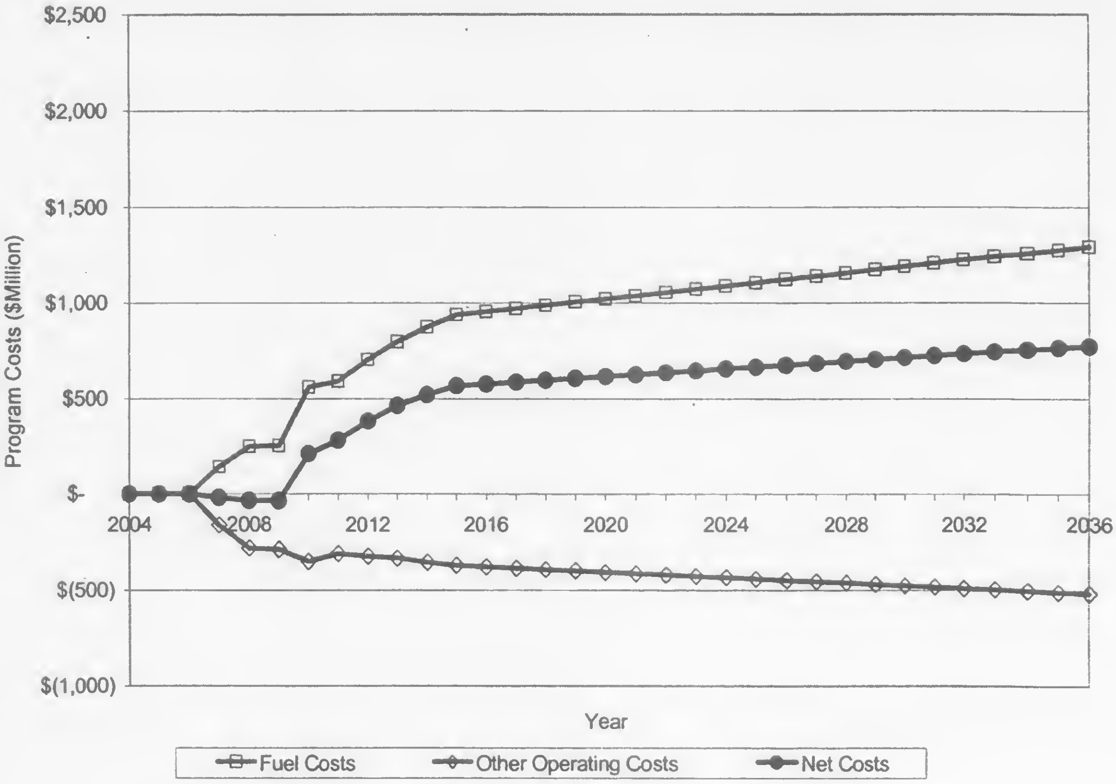
Pollutant	30 year discounted lifetime cost per ton at 3%	30 year discounted lifetime cost per ton at 7%	Long-term cost per ton in 2030
NO_X+NMHC	$1,010	$1,160	$680
PM	11,200	11,800	9,300
SO_X	690	620	810

3. Annual Costs for the NRLM Fuel-only Scenario

Cent per gallon costs for the new 500 ppm NRLM fuel, the new 500 ppm L&M fuel, the new 15 ppm NR fuel, and the new 15 ppm NRLM fuel were presented in section IV.A. Having this fuel will result in maintenance savings associated with increased oil change intervals for both the new and the existing fleet of nonroad, locomotive, and marine engines. These maintenance savings were discussed in section VI.B. There are no engine and equipment costs associated with the NRLM fuel-only scenario because new engine emissions standards are not included in that scenario. Figure VI.D–2 shows the annual costs associated with the NRLM fuel-only program.

As can be seen in figure VI.D–1, the costs for refining and distributing the fuel range from $250 million in 2008 to nearly $1.3 billion in 2036. The increase in fuel costs in 2010 reflect the change to higher cost 15 ppm NR fuel. Fuel costs continue to grow as more fuel is consumed by the increasing number of engines and equipment. The fuel costs are largely offset by the maintenance savings that range from $250 million in 2008 to $500 million in 2036. As a whole, the net cost of the program in each year ranges from a small net savings in 2008 to around $780 million in 2036. The net present value (*i.e.*, the value in 2004) of the net costs associated with the NRLM fuel-only program during the 30 year period from 2007 to 2036 is estimated at $9.2 billion using a 3 percent discount rate and $4.6 billion using a 7 percent discount rate.

Figure VI.D-2. – Annual Costs of the NRLM Fuel-only Scenario



4. Cost Per Ton of Emissions Reduced for the NRLM Fuel-Only Scenario

The fuel-borne sulfur reduction under the NRLM fuel-only scenario will result in significant reductions of both SO_2 and PM emissions. Since there are no new engine standards associated with the NRLM fuel-only scenario, the emissions reductions that result are entirely fuel-derived. Roughly 98 percent of fuel-borne sulfur is converted to SO_2 in the engine with the remaining two percent being exhausted as sulfate PM. We have allocated one-third of the costs of this program to PM control and two-thirds to SO_2 control. This is consistent with the cost accounting we have used throughout our analysis in that costs associated with fuel-derived emissions reductions are attributed one-third to PM control and two-thirds to SO_2 control.

As discussed above, the 30 year net present value of costs associated with the fuel-only program are estimated at $9.2 billion using 3 percent discounting and $4.6 billion using 7 percent discounting. We have estimated the 30 year net present value of the SO_2 emission reductions at 5.7 million tons and PM emission reductions at 462,000 tons using 3 percent discounting, 3.2 million tons and 255,000 tons, respectively, using 7 percent discounting.

Table VI.D–1 shows the cost per ton of emissions reduced as a result of the NRLM fuel-only scenario. The cost per ton numbers include costs and emissions reductions that will occur from both the new and the existing fleet (i.e., those pieces of nonroad equipment that were sold into the market prior to the new fuel standards) of nonroad, locomotive, and marine engines.

TABLE VI.D–2.—NRLM FUEL-ONLY SCENARIO—30-YEAR AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON

[$2002]

Pollutant	30 year discounted lifetime cost per ton at 3%	30 year discounted lifetime cost per ton at 7%	Long-term cost per ton in 2030
PM	$6,600	$6,000	$7,900
SO_2	1,070	970	1,270

We also considered the cost per ton of the NRLM fuel-only scenario without including the expected maintenance savings associated with low sulfur fuel. Without the maintenance savings, the 30 year discounted cost per ton of PM reduced would be $11,800 and of SO_2 reduced would be $1,900 using 3 percent discounting and $11,200 and $1,800, respectively, using 7 percent discounting. More detail on how the costs and cost per ton numbers associated with the NRLM fuel-only scenario were calculated can be found in the RIA.

5. Comparison With Other Means of Reducing Emissions

In comparison with other emissions control programs, we believe that the Tier 4 programs represent a cost effective strategy for generating substantial NO_X+NMHC, PM, and SO_2 reductions. This can be seen by comparing the cost per ton of emissions reduced by the NRLM fuel-only scenario (*i.e.*, reducing fuel sulfur to 500 ppm in 2007 and 15 ppm in 2010 without any new nonroad engine standards) and the cost per ton of emissions reduced by the full NRLM fuel and nonroad engine program (*i.e.*, fuel control and new engine standards) with a number of standards that EPA has adopted in the past. Tables VI.D–3 and VI.D–4 summarize the cost per ton of several past EPA actions to reduce emissions of NO_X+NMHC and PM from mobile sources, all of which were considered by EPA to be appropriate.

TABLE VI.D–3.—NRT4 COST PER TON COMPARISON TO PREVIOUS MOBILE SOURCE PROGRAMS FOR NO_X + NMHC

Program	$/ton
Tier 4 Nonroad Diesel (full program)	1,010
Tier 2 Nonroad Diesel	630
Tier 3 Nonroad Diesel	430
Tier 2 vehicle/gasoline sulfur	1,400–2,350
2007 Highway HD	2,240
2004 Highway HD	220–430
Tier 1 vehicle	2,150–2,910
NLEV	2,020
Marine SI engines	1,220–1,930
On-board diagnostics	2,410
Marine CI engines	30–190
Large SI Exhaust	80
Recreational Marine	670

Note: Costs adjusted to 2002 dollars using the Producer Price Index for Total Manufacturing Industries.

TABLE VI.D–4. "NRT4 COST PER TON COMPARISON TO PREVIOUS MOBILE SOURCE PROGRAMS FOR PM

Program	$/ton
Tier 4 Nonroad Diesel (full program)	11,200
Tier 4 NRLM fuel-only (fuel-only scenario)	6,800
Tier 1/Tier 2 Nonroad Diesel	2,390
2007 Highway HD	14,180
Marine CI engines	4,040–5,440
1996 urban bus	12,780–20,450
Urban bus retrofit/rebuild	31,530
1994 highway HD diesel	21,780–25,500

Note: Costs adjusted to 2002 dollars using the Producer Price Index for Total Manufacturing Industries.

To compare the cost per ton of SO_2 emissions reduced, we looked at the cost per ton for the Title IV (acid rain) SO_2 trading programs. This information is found in EPA report 430/R–02–004, "Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model", in Figure 9.11 on page 9–14 (*www.epa.gov/airmarkets/epa-ipm/index.html#documentation*). The SO_2 cost per ton results of the full Tier 4 program presented in table VI.D–2 compare very favorably with the program shown in table VI.D–5.

TABLE VI.D–5.—NRT4 COST PER TON COMPARISON TO SO_2 FROM BOTH THE EPA BASE CASE 2000 FOR THE TITLE IV SO_2 TRADING PROGRAMS AND THE PROPOSED INTERSTATE AIR QUALITY RULE

Program	$/ton
Tier 4 Nonroad Diesel (full program).	$690
Tier 4 Nonroad Diesel (fuel-only scenario).	1,070
Title IV SO_2 Trading Programs.	490 in 2010 to 610 in 2020
Interstate Air Quality Rule (average cost).	730 in 2010 to 830 in 2015

Note: Costs adjusted to 2002 dollars using the Producer Price Index for Total Manufacturing Industries.

As the above comparisons show, both the NRLM fuel-only scenario, when viewed by itself, and the combination of NRLM fuel and nonroad engine standards, are both cost effective strategies to achieve the associated emissions reductions.

E. Do the Benefits Outweigh the Costs of the Standards?

Our analysis of the health and environmental benefits to be expected from this final rule are presented in this section. Briefly, the analysis projects major benefits throughout the period from initial implementation of the rule over a 30 year period through 2036. As described below, thousands of deaths and other serious health effects would be prevented, yielding a net present value in 2004 of those benefits we could monetize of approximately $805 billion dollars using a 3 percent discount rate and $352 billion using a 7 percent discount rate. These benefits exceed the net present value of the social cost of the proposal ($27 billion using a 3 percent discount rate and $14 billion using a 7 percent discount rate) by $780 billion using a 3 percent discount rate and $340 billion using a 7 percent discount rate.

1. What Were the Results of the Benefit-Cost Analysis?

Table VI.E–1 presents the primary estimate of reduced incidence of PM-related health effects for the years 2020 and 2030. 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-related benefits associated with the reduction of several health effects. In 2030, we estimate that there will be 12,000 fewer fatalities in adults[239] and 20 fewer fatalities in infants per year associated with fine PM, and the rule will result in about 5,600 fewer cases of chronic bronchitis, 8,900 fewer hospitalizations (for respiratory and cardiovascular disease combined), and result in 1 million days per year when adults miss work because of their respiratory symptoms and 5.9 million days of when adults must restrict their activity due to respiratory illness. We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma

[239] 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 future rulemakings.

attacks.[240] We were unable to quantify the benefits related to ozone and other pollutants for the final rule, although we do present some preliminary ozone modeling in Chapter 9 of the RIA.

Table VI.E–2 presents the total monetized benefits for the years 2020 and 2030. This table also indicates with a "B" those additional health and environmental effects which we were unable to quantify or monetize. These effects are additive to estimate of total benefits, and EPA believes there is considerable value to the public of the benefits that could not be monetized. A full listing of the benefit categories that could not be quantified or monetized in our estimate are provided in table VI.E–6.

In summary, EPA's primary estimate of the benefits of the rule are $83 + B billion in 2030 using a 3 percent discount rate and $78 + B billion using a 7 percent discount rate. In 2020, total monetized benefits are $42 + B billion using a 3 percent discount rate and $41 + B billion using a 7 percent discount rate. These estimates account for growth in real gross domestic product (GDP) per capita between the present and the years 2020 and 2030. 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 VI.E–1.—REDUCTIONS IN INCIDENCE OF PM-RELATED ADVERSE HEALTH EFFECTS ASSOCIATED WITH THE FINAL NONROAD DIESEL ENGINE AND FUEL STANDARDS FULL PROGRAM

Endpoint	Avoided incidence[a] (cases/year)	
	2020	2030
Premature mortality[b]: Long-term exposure (adults, 30 and over)	6,500	12,000
Infant mortality (infants under one year)	15	22
Chronic bronchitis (adults, 26 and over)	3,500	5,600
Non-fatal myocardial infarctions (adults, 18 and older)	8,700	15,000
Hospital admissions—Respiratory (adults, 20 and older)[c]	2,800	5,100
Hospital admissions—Cardiovascular (adults, 20 and older)[d]	2,300	3,800
Emergency Room Visits for Asthma (18 and younger)	3,800	6,000
Acute bronchitis (children, 8–12)	8,400	13,000
Asthma exacerbations (asthmatic children, 6–18)	120,000	200,000
Lower respiratory symptoms (children, 7–14)	100,000	160,000
Upper respiratory symptoms (asthmatic children, 9–11)	76,000	120,000
Work loss days (adults, 18–65)	670,000	1,000,000
Minor restricted activity days (adults, age 18–65)	4,000,000	5,900,000

Notes: [a] Incidences are rounded to two significant digits. [b] Premature mortality associated with ozone is not separately included in this analysis. [c] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma. [d] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

TABLE VI.E–2.—EPA PRIMARY ESTIMATE OF THE ANNUAL QUANTIFIED AND MONETIZED BENEFITS ASSOCIATED WITH IMPROVED PM AIR QUALITY RESULTING FROM THE FINAL NONROAD DIESEL ENGINE AND FUEL STANDARDS FULL PROGRAM

Endpoint	Monetary Benefits[a, b] (millions 2000$, Adjusted for Income Growth)	
	2020	2030
Premature mortality[c]: (adults, 30 and over)		
3% discount rate	$41,000	$77,000
7% discount rate	38,000	72,000
Infant mortality (infants under one year)	97	150
Chronic bronchitis (adults, 26 and over)	1,500	2,400
Non-fatal myocardial infarctions[d]		
3% discount rate	750	1,200
7% discount rate	720	1,200
Hospital Admissions from Respiratory Causes[e]	49	92
Hospital Admissions from Cardiovascular Causes[f]	51	83
Emergency Room Visits for Asthma	1.1	1.7
Acute bronchitis (children, 8–12)	3.2	5.2
Asthma exacerbations (asthmatic children, 6–18)	5.7	9.2
Lower respiratory symptoms (children, 7–14)	1.7	2.7
Upper respiratory symptoms (asthmatic children, 9–11)	2.0	3.2
Work loss days (adults, 18–65)	92	130
Minor restricted activity days (adults, age 18–65)	210	320
Recreational visibility (86 Class I Areas)	1,000	1,700
Monetized Total[g].		
3% discount rate	44,000+B	83,000+B

[240] Our PM-related estimate in 2030 incorporates significant reductions of 160,000 fewer cases of lower respiratory symptoms in children ages 7 to 14 each year, 120,000 fewer cases of upper respiratory symptoms (similar to cold symptoms) in asthmatic children each year, and 13,000 fewer cases of acute bronchitis in children ages 8 to 12 each year. In addition, we estimate that this rule will reduce almost 6,000 emergency room visits for asthma attacks in children each year from reduced exposure to particles. Additional incidents would be avoided from reduced ozone exposures. Asthma is the most prevalent chronic disease among children and currently affects over seven percent of children under 18 years of age.

TABLE VI.E–2.—EPA PRIMARY ESTIMATE OF THE ANNUAL QUANTIFIED AND MONETIZED BENEFITS ASSOCIATED WITH IMPROVED PM AIR QUALITY RESULTING FROM THE FINAL NONROAD DIESEL ENGINE AND FUEL STANDARDS FULL PROGRAM—Continued

Endpoint	Monetary Benefits[a, b] (millions 2000$, Adjusted for Income Growth)	
	2020	2030
7% discount rate	42,000+B	78,000+B

Notes: [a] Monetary benefits are rounded to two significant digits. [b] Monetary benefits are adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2020 or 2030). [c] Valuation of base estimate assumes discounting over the lag structure described in the RIA Chapter 9. [d] Estimates assume costs of illness and lost earnings in later life years are discounted using either 3 or 7 percent. [e] Respiratory hospital admissions for PM includes admissions for COPD, pneumonia, and asthma. [f] Cardiovascular hospital admissions for PM includes total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure. [g] B represents the monetary value of the unmonetized health and welfare benefits. A detailed listing of unquantified PM, ozone, CO, and NMHC related health effects is provided in Table VI.E–6.

The estimated social cost (measured as changes in consumer and producer surplus) in 2030 to implement the final rule from table VI.E–3 is $2.0 billion (2000$). Thus, the net benefit (social benefits minus social costs) of the program at full implementation is approximately $81 + B billion using a 3 percent discount rate and $78 + B billion using a 7 percent discount rate. In 2020, partial implementation of the program yields net benefits of $42 + B billion using a 3 percent discount rate and $41 + B billion using a 7 percent discount rate. Therefore, implementation of the final rule is expected to provide society with a net gain in social welfare based on economic efficiency criteria. Table VI.E–3 presents a summary of the benefits, costs, and net benefits of the final rule's full program. Figure VI–E.1 displays the stream of benefits, costs, and net benefits of the Nonroad Diesel Vehicle Rule from 2007 to 2036 using two different discount rates. In addition, table VI.E–4 presents the net present value of the stream of benefits, costs, and net benefits associated with the rule for this 30 year period. The total net present value in 2004 of the stream of net benefits (benefits minus costs) is $780 billion using a 3 percent discount rate and $340 billion using a 7 percent discount rate.

TABLE VI.E–3.—SUMMARY OF BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL NONROAD DIESEL ENGINE AND FUEL STANDARDS FULL PROGRAM

	2020[a] (Billions of 2000 dollars)	2030[a] (Billions of 2000 dollars)
Social Costs[b]	$1.8	$2.0.
Social Benefits:[b, c, d]		
CO, VOC, Air Toxic-related benefits	Not monetized	Not monetized.
Ozone-related benefits	Not monetized	Not monetized.
PM-related Welfare benefits	$1.0	$1.7.
PM-related Health benefits [3% discount]	$43 + B	$81 + B.
PM-related Health benefits [7% discount]	$41 + B	$78 + B.
Net Benefits (Benefits-Costs) [3% discount][c]	$44 + B	$81 + B.
Net Benefits (Benefits-Costs) [7% discount][c]	$42 + B	$78 + B.

Notes: [a] All costs and benefits are calculated using 3 and 7 percent discount rates and are rounded to two significant digits. Numbers may appear not to sum due to rounding.

[b] Note that costs are the total costs of reducing all pollutants, including CO, VOCs and air toxics, as well as NO_X and PM. Costs were converted to 2000$ using the PPI for Total Manufacturing Industries. Benefits in this table are associated only with PM endpoints related to direct PM, NO_X and SO_2 reductions in 48-states.

[c] Not all possible benefits or disbenefits are quantified and monetized in this analysis. Potential benefit categories that have not been quantified and monetized are listed in table VI.E–6. B is the sum of all unquantified benefits and disbenefits.

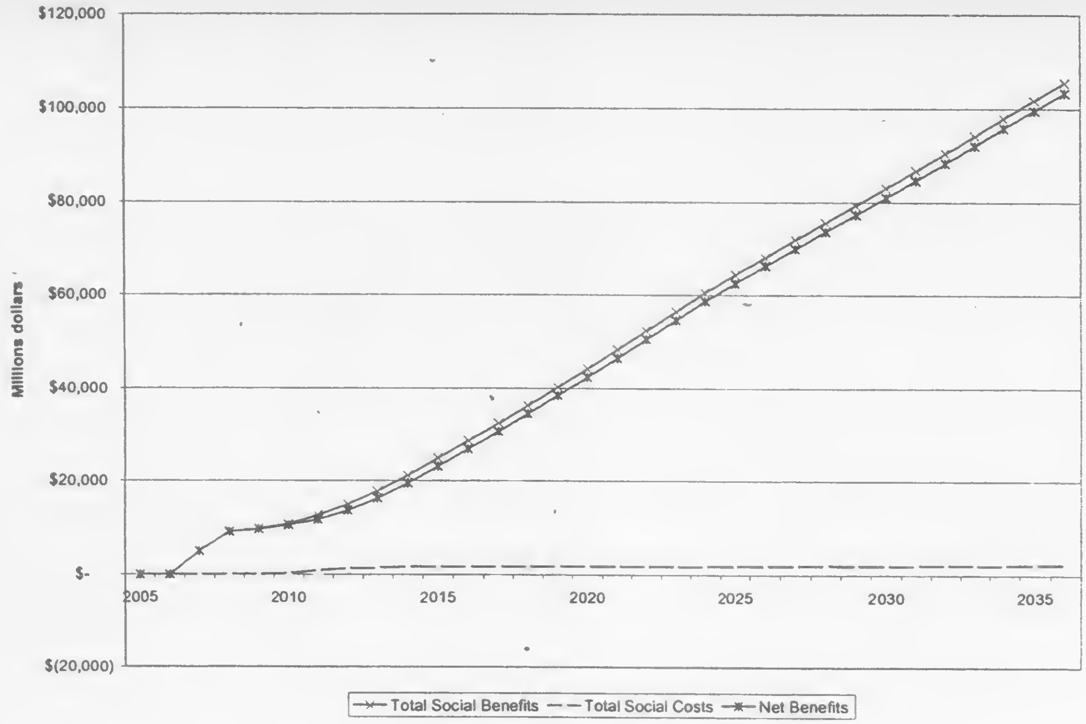


Figure VI.E-1. – Stream of Benefits, Costs, and Net Benefits of the Final Nonroad Diesel Engine and Fuel Standards Full Program

TABLE VI.E–4.—NET PRESENT VALUE IN 2004 OF THE STREAM OF 30 YEARS OF BENEFITS, COSTS, AND NET BENEFITS FOR THE FULL NONROAD DIESEL ENGINE AND FUEL STANDARDS

[Billions of 2000$]

	3% discount rate	7% discount rate
Social Costs	$27	$14
Social Benefits	805	352
Net Benefits [a]	780	340

Notes: [a] Numbers do not add due to rounding. Benefits represent 48-state benefits and exclude home heating oil sulfur reduction benefits, whereas costs include 50-state estimates.

In addition, we analyzed the social benefits and costs of the fuel-only components of the program, as discussed in the RIA. EPA's primary estimate of the benefits of the fuel-only component of the final rule are approximately $28 + B billion in 2030 using a 3 percent discount rate and $25 + B billion using a 7 percent discount rate. In 2020, total monetized benefits are approximately $18 + B billion using a 3 percent discount rate and $16 + B billion using a 7 percent discount rate. These estimates account for growth in real gross domestic product (GDP) per capita between the present and the years 2020 and 2030. We present the engineering costs of implementing the fuel-only components of the rule. Engineering compliance costs are very similar to the total social costs for the entire program. The net benefit (social benefits minus engineering costs) of the fuel-only program at full implementation is approximately $330 + B billion using a 3 percent discount rate and $160 + B billion using a 7 percent discount rate. Therefore, implementation of the fuel-only components of the final rule is expected to provide society with a net gain in social welfare based on economic efficiency criteria. Table VI.E–5 presents a summary of the social benefits, engineering costs, and net benefits of the final rule's fuel-only program for a 30 year period.

TABLE VI.E–5.—NET PRESENT VALUE IN 2004 OF THE STREAM OF BENEFITS, COSTS, AND NET BENEFITS FOR THE FUEL-ONLY STANDARDS

[Billions of 2000$]

	3% Discount rate	7% Discount rate
Costs	$9.2	$4.6
Social Benefits	340	160
Net Benefits	330	160

Notes:

[A] Results are rounded to two significant digits. Sums may differ because of rounding.

[B] Engineering costs are presented instead of social costs. As discussed in previous chapters, total engineering costs include fuel costs (refining, distribution, lubricity) and other operating costs (oil change maintenance savings).

[C] Note that costs are the total costs of reducing all pollutants, including CO, VOCs and air toxics, as well as NO_X and PM. Benefits in this table are associated only with PM, NO_X and SO_2 reductions. The estimates do not include the benefits of reduced sulfur in home heating oil or benefits in Alaska or Hawaii.

2. What Was Our Overall Approach to the Benefit-Cost Analysis?

The basic question we sought to answer in the benefit-cost analysis was, "What are the net yearly economic benefits to society of the reduction in mobile source emissions likely to be achieved by this proposed rulemaking?" In designing an analysis to address this question, we selected two future years for analysis (2020 and 2030) that are representative of the stream of benefits and costs at partial and full-implementation of the program.

To quantify benefits, we evaluated PM-related health effects (including directly emitted PM and sulfate, as well as SO_2 and NO_X contributions to fine particulate matter). Our approach requires the estimation of changes in air quality expected from the rule and then estimating the resulting impact on health. In order to characterize the benefits of today's 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 for a preliminary control option for nonroad diesel engines and fuels. Results from this modeling conducted for 2020 and 2030 are then scaled and transferred to the emission reductions expected from the final rule. We also transferred modeled results by using scaling factors associated with time to examine the stream of benefits in years other than 2020 and 2030.

More specifically, our health benefits assessment is conducted in two phases. Due to the time requirements for running the sophisticated emissions and air quality models, it is often necessary to select an example set of emission reductions to use for the purposes of emissions and air quality modeling early in the development of the proposal. In phase one, we evaluate the PM- and ozone-related health effects associated with a modeled preliminary control option that was a close approximation of the standards in the years 2020 and 2030. Using information from the modeled preliminary control option on the changes in ambient concentrations of PM and ozone, we then estimate the number of reduced incidences of illnesses, hospitalizations, and premature fatalities associated with this scenario and estimate the total economic value of these health benefits. Based on public comment and other data described in the RIA, the standards we are finalizing in this rulemaking are slightly different in the amount of emission reductions expected to be achieved in 2020 and 2030 relative to the modeled scenario. Thus, in phase two of the analysis, we apportion the results of the phase one analysis to the underlying NO_X, SO_2, and PM emission reductions and scale the apportioned benefits to reflect differences in emissions reductions between the modeled preliminary control option and the proposed standards. The sum of the scaled benefits for the PM, SO_2, and NO_X emission reductions provide us with the total benefits of the rule.

The benefit estimates derived from the modeled preliminary control option in phase one of our analysis uses an analytical structure and sequence similar to that used in the benefits analyses for the Heavy Duty Engine/ Diesel Fuel final rule and in the "section 812 studies" to estimate the total benefits and costs of the full Clean Air Act.[241] We used many of the same models and assumptions used in the Heavy Duty Engine/Diesel Fuel analysis 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), by the public, and by other federal agencies. In addition, we will be working through the next section 812 study process to enhance our methods.[242]

The benefits transfer method used in phase two of the analysis is similar to that used to estimate benefits in the recent analysis of the 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.

On September 26, 2002, the National Academy of Sciences (NAS) released a report on its review of the Agency's methodology for analyzing the health benefits of measures taken to reduce air pollution. The report focused on EPA's approach for estimating the health benefits of regulations designed to reduce concentrations of airborne PM.

In its report, the NAS panel said that EPA has generally used a reasonable framework for analyzing the health benefits of PM-control measures. It recommended, however, that the Agency take a number of steps to improve its benefits analysis. In particular, the NAS stated that the Agency should:

- Include benefits estimates for a range of regulatory options;
- Estimate benefits for intervals, such as every five years, rather than a single year;
- Clearly state the projected baseline statistics used in estimating health benefits, including those for air emissions, air quality, and health outcomes;
- Examine whether implementation of proposed regulations might cause unintended impacts on human health or the environment;
- When appropriate, use data from non-U.S. studies to broaden age ranges to which current estimates apply and to include more types of relevant health outcomes; and
- Begin to move the assessment of uncertainties from its ancillary analyses into its Base analyses by conducting probabilistic, multiple-source uncertainty analyses. This assessment should be based on available data and expert judgment.

Although the NAS made a number of recommendations for improvement in EPA's approach, it found that the studies selected by EPA for use in its benefits analysis were generally reasonable choices. In particular, the NAS agreed with EPA's decision to use cohort studies to derive benefits estimates. It also concluded that the Agency's selection of the American Cancer Society (ACS) study for the evaluation of PM-related premature mortality was reasonable, although it noted the publication of new cohort studies that should be evaluated by the Agency.

EPA has addressed many of the NAS comments in our analysis of the final rule. We provide benefits estimates for each year over the rule implementation period for a wide range of regulatory alternatives, in addition to our final emission control program. We use the estimated time path of benefits and costs to calculate the net present value of benefits of the rule. In the RIA, we provide baseline statistics for air emissions, air quality, population, and health outcomes. We have examined how our benefits estimates might be impacted by expanding the age ranges to which epidemiological studies are applied, and we have added several new health endpoints, including non-fatal heart attacks, which are supported by both U.S. studies and studies conducted in Europe. We have also improved the documentation of our methods and

[241] The section 812 studies include: (1) U.S. EPA, Report to Congress: The Benefits and Costs of the Clean Air Act, 1970 to 1990, October 1997 (also known as the "Section 812 Retrospective Report"); and (2) the first in the ongoing series of prospective studies estimating the total costs and benefits of the Clean Air Act (see EPA report number: EPA–410–R–99–001, November 1999). *See* Docket A–99–06, Document II–A–21.

[242] Interested parties may want to consult the webpage: *http://www.epa.gov/science1* regarding components of our analytical blueprint.

provided additional details about model assumptions.

Several of the NAS recommendations addressed the issue of uncertainty and how the Agency can better analyze and communicate the uncertainties associated with its benefits assessments. In particular, the Committee expressed concern about the Agency's reliance on a single value from its analysis and suggested that EPA develop a probabilistic approach for analyzing the health benefits of proposed regulatory actions. The Agency agrees with this suggestion and is working to develop such an approach for use in future rulemakings.

EPA plans to continue to refine its plans for addressing uncertainty in its analyses. EPA conducted a pilot study to address uncertainty in important analytical parameters such as the concentration-response relationship for PM-related premature mortality. EPA is also conducting longer-term elements intended to provide scientifically sound, peer-reviewed characterizations of the uncertainty surrounding a broader set of analytical parameters and assumptions, including but not limited to emissions and air quality modeling, demographic projections, population health status, concentration-response functions, and valuation estimates.

3. What Are the Significant Limitations of the Benefit-Cost Analysis?

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 which can be quantified. While these general uncertainties in the underlying scientific and economics literatures, which can cause the valuations to be higher or lower, are discussed in detail in the Regulatory Support Document and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this final rule include the following:

- The exclusion of potentially significant benefit categories (such as health, odor, and ecological benefits of reduction in CO, VOCs, air toxics, and ozone);
- Errors in measurement and projection for variables such as population growth;
- Uncertainties in the estimation of future year emissions inventories and air quality;
- Uncertainties associated with the scaling of the results of the modeled benefits analysis to the proposed standards, especially regarding the assumption of similarity in geographic distribution between emissions and human populations and years of analysis;
- Variability in the estimated relationships of health and welfare effects to changes in pollutant concentrations;
- Uncertainties in exposure estimation; and
- 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 final rulemaking in future years under a set of assumptions. Accordingly, we present a primary estimate of the total benefits, based on our interpretation of the best available scientific literature and methods and supported by the SAB–HES and the NAS.

Some of the key assumptions underlying the primary estimate for the premature mortality which accounts for 90 percent of the total benefits we were able to quantify include the following:

(1) Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been definitively established, the weight of the available epidemiological evidence supports an assumption of causality.

(2) All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) The impact function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that are in attainment with fine particle standard and those that do not meet the standard.

(4) The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

We provide sensitivity analyses to illustrate the effects of uncertainty about key analytical assumptions in the RIA.

In addition, one significant limitation to the benefit transfer method applied in this analysis is the inability to scale ozone-related benefits. Because ozone is a homogeneous gaseous pollutant, it is not possible to apportion ozone benefits to the precursor emissions of NO_X and VOC. Coupled with the potential for NO_X reductions to either increase or decrease ambient ozone levels, this prevents us from scaling the benefits associated with a particular combination of VOC and NO_X emissions reductions to another. Because of our inability to scale ozone benefits, we do not include ozone benefits as part of the monetized benefits of the proposed standards. For the most part, ozone benefits contribute substantially less to the monetized benefits than do benefits from PM, thus their omission will not materially affect the conclusions of the benefits analysis. Although we expect economic benefits to exist, we were unable to quantify or to value specific changes in ozone, CO or air toxics because we did not perform additional air quality modeling.

There are also a number of health and environmental effects which 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 new standards, not just those benefits and costs which could be expressed here in dollar terms. A complete listing of the benefit categories that could not be quantified or monetized in our estimate are provided in Table VI.E–6. These effects are denoted by "B" in Table VI.E–3 above, and are additive to the estimates of benefits.

TABLE VI.E–6.—ADDITIONAL, NON-MONETIZED BENEFITS OF THE NONROAD DIESEL ENGINE AND FUEL STANDARDS

Pollutant	Unquantified effects
Ozone Health	Premature mortality [a]. Respiratory hospital admissions. Minor restricted activity days. 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. Increased school absence rates.
Ozone Welfare	Decreased yields for commercial forests. Decreased yields for fruits and vegetables. Decreased yields for 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. Cancer. 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 to commercial freshwater fishing. Impacts of acidic deposition to recreation in terrestrial ecosystems. Reduced existence values for currently healthy ecosystems. Impacts of nitrogen deposition on commercial fishing, agriculture, and forests.
CO Health	Premature mortality [a]. Behavioral effects.
HC Health [b]	Cancer (benzene, 1,3-butadiene, formaldehyde, acetaldehyde). Anemia (benzene). Disruption of production of blood components (benzene). Reduction in the number of blood platelets (benzene). Excessive bone marrow formation (benzene). Depression of lymphocyte counts (benzene). Reproductive and developmental effects (1,3-butadiene). Irritation of eyes and mucus membranes (formaldehyde). Respiratory irritation (formaldehyde). Asthma attacks in asthmatics (formaldehyde). Asthma-like symptoms in non-asthmatics (formaldehyde). Irritation of the eyes, skin, and respiratory tract (acetaldehyde). Upper respiratory tract irritation and congestion (acrolein).
HC Welfare	Direct toxic effects to animals. Bioaccumulation in the food chain. Damage to ecosystem function. Odor.

Notes: [a] Premature mortality associated with ozone and carbon monoxide is not separately included in this analysis. In this analysis, we assume that the Pope, *et al.* C-R function for premature mortality captures both PM mortality benefits and any mortality benefits associated with other air pollutants.
[b] Many of the key hydrocarbons related to this rule are also hazardous air pollutants listed in the Clean Air Act.

F. Economic Impact Analysis

We prepared a draft Economic Impact Analysis (EIA) for this rule to estimate the economic impacts of the proposed control program on producers and consumers of nonroad engines, equipment, fuel, and related industries.[243] We received comments on

[243] This analysis is based on an earlier version of the engineering costs developed for this rule. The

Continued

our draft analysis from stakeholders representing agricultural interests, equipment rental and dealer interests, and equipment manufacturers. The commenters conveyed their concerns about our general analytic approach and some of the model assumptions. As explained in our responses to these comments, which can be found in the Summary and Analysis of Comments document prepared for this final rule, we do not believe these comments require us to adjust our EIA methodology. We did adjust the methodology, however, to estimate the economic impacts of the fuel sulfur content requirements on the locomotive and marine sectors. As explained below, this revision was necessary to correct an oversight in the draft EIA. We also revised the price and quantity data inputs to the model to make them consistent with the revised engine and fuel cost analyses described earlier in this section.

This section briefly describes the methodology we used to estimate the economic impacts of this final rule, including the model revisions for the marine and locomotive fuel sectors, and the results of that analysis. A detailed description of the Nonroad Diesel Economic Impact Model (NDEIM) prepared for this analysis, the model inputs, and several sensitivity analyses can be found in Chapter 10 of Final Regulatory Impact Analysis prepared for this rule.

1. What Is an Economic Impact Analysis?

An Economic Impact Analysis is prepared to inform decision makers within the Agency about the potential economic consequences of a regulatory action. The analysis contains estimates of the social costs of a regulatory program and explores the distribution of these costs across stakeholders. These estimated social costs can then be compared with estimated social benefits (as presented in Section VI.E). As defined in EPA's *Guidelines for Preparing Economic Analyses, social costs* are the value of the goods and services lost by society resulting from (a) the use of resources to comply with and implement a regulation and (b) reductions in output.[244] In this analysis, social costs are explored in two steps. In the first step, called the market analysis, we estimate how prices and quantities of good directly and indirectly affected by the emission control program can be expected to change once the emission control program goes into effect. The estimated price and quantity changes for engines, equipment, fuel, and goods produced using these inputs are examined separately. In the second step, called the economic welfare analysis, we look at the total social costs associated with the program and their distribution across stakeholders. The analysis is based on compliance cost estimates and baseline market conditions for prices and quantities of engines, equipment, and fuel produced presented earlier in this section.

In this EIA, we look at price and quantity impacts for engine, equipment, diesel fuel, and goods produced with these inputs. With regard to the goods produced with these inputs, we distinguish between three application markets: agriculture, construction, and manufacturing. It should be noted from the outset that diesel engines, equipment, and fuel represent only a small portion of the total production costs for each of the three application market sectors (the final users of the engines, equipment and fuel affected by this rule). Other more significant production costs include land, labor, other capital, raw materials, insurance, profits, etc. These other production costs are not affected by this emission control program. This is important because it means that this rule directly affects only a small part of total inputs for the relevant markets. Therefore, the rule is not expected to have a large adverse impact on output and prices of goods produced in the three application sectors.

It should also be noted that our analysis of the impacts on the three application markets is limited to market output. The economic impacts on particular groups of application market suppliers (*e.g.*, the profitability of farm production units or manufacturing or construction firms) or particular groups of consumers (*e.g.*, households and companies that consume agricultural goods, buildings, or durable or consumer goods) are not estimated. In other words, while we estimate that the application markets will bear most of the burden of the regulatory program and we apportion the decrease in application market surplus between application market producers and application market consumers, we do not estimate how those social costs will be shared among specific application market producers and consumers (*e.g.*, farmers and households). In some cases, application market producers may be able to pass most if not all of their increased costs to the ultimate consumers of their products; in other cases, they may be obliged to absorb a portion of these costs. While some commenters requested that we perform a sector-by-sector analysis of application market producers and consumers, we do not believe this is appropriate. The focus on market-level impacts in this analysis is appropriate because the standards in this emission control program are technical standards that apply to nonroad engines, equipment, and fuel regardless of how they are used and the structure of the program does not suggest that different sectors will be affected differently by the requirements. In addition, the results of our EIA suggest that the overall burden on the application market is expected to be small: approximately 0.1 percent increase in prices, on average, and less than 0.02 percent decrease in production, on average. Estimated economic impacts of this size do not warrant performing a sector-by-sector analysis to investigate whether some subsectors may be affected disproportionately.

Finally, as a market-level model, the NDEIM estimates the economic impacts of the rule on the engine, equipment, and application markets and the transportation service sector. It is not a firm-level analysis and therefore the equipment demand elasticity facing any particular manufacturer may be greater than the demand elasticity of the market as a whole. This difference can be important, particularly where the rule affects different firms' costs over different volumes of production. However, to the extent there are differential effects, EPA believes that the wide array of flexibilities provided in this rule are adequate to address any cost inequities that are likely to arise.

2. What Methodology Did EPA Use in This Economic Impact Analysis?

EPA used the same methodology in this final EIA as was used in the draft EIA. The model was revised to accommodate analysis of the locomotive and marine fuel sectors.

a. Conceptual Approach

The Nonroad Diesel Economic Impact Model (NDEIM) uses a multi-market

final cost estimates for the engine program are slightly higher ($142 million) and the final fuel costs are slightly lower ($246 million), resulting in a 30-year net present value of $27.1 billion (30 year net present values in the year 2004, using a 3 percent discount rate, $2002) or $104 million less than the engineering costs used in this analysis. We do not expect that the revised engineering costs would change the overall results of this economic impact analysis given the small portion of engine, equipment, and fuel costs to total production costs for goods and services using these inputs and given the inelastic value of the estimated demand elasticities for the application markets.

[244] *EPA Guidelines for Preparing Economic Analyses*, EPA 240–R–00–003, September 2000, p 113.

analysis framework that considers interactions between regulated markets and other markets to estimate how compliance costs can be expected to ripple through these markets. In the NDEIM, compliance costs are directly borne by engine manufacturers, equipment manufacturers, petroleum refiners and fuel distributors. Depending on market characteristics, some or all of these compliance costs will be passed on through the supply chain in the form of higher input prices for the application markets (in this case, construction, agriculture, and manufacturing) which in turn affect prices and quantities of goods produced in those application markets. Producers in the application markets adjust their demand for diesel engines, equipment, and fuel in response to these input price changes and consumer demand for application market outputs. This information is passed back to the suppliers of diesel equipment, engines, and fuel in the form of purchasing decisions. The NDEIM explicitly models these interactions and estimates behavioral responses that lead to new equilibrium prices and output for all sectors and the resulting distribution of social costs across the modeled sectors.

b. Markets Examined

The NDEIM uses a multi-market partial equilibrium approach to track changes in price and quantity for 62 integrated product markets, as follows:

• 7 diesel engine markets: less than 25 hp, 26 to 50 hp, 51 to 75 hp, 76 to 100 hp, 101 to 175 hp, 176 to 600 hp, and greater than 600 hp. The EIA includes more horsepower categories than the standards to allow more efficient use of the engine compliance costs estimates. The additional categories also allow estimating economic impacts for a more diverse set of markets.

• 42 diesel equipment markets: 7 horsepower categories within 7 application categories: agricultural, construction, general industrial, pumps and compressors, generator and welder sets, refrigeration and air conditioning, and lawn and garden. There are 7 horsepower/application categories that did not have sales in 2000 and are not included in the model, so the total number of diesel equipment markets is 42 rather than 49.

• 3 application markets: agricultural, construction, and manufacturing.

• 8 nonroad diesel fuel markets: 2 sulfur content levels (15 ppm and 500 ppm) for each of 4 PADDs. PADDs 1 and 3 are combined for the purpose of this analysis. It should be noted that PADD 5 includes Alaska and Hawaii. Also, California fuel volumes that are not affected by the program (because they are covered by separate California nonroad diesel fuel standards) are not included in the analysis.

• 2 transportation service markets: locomotive and marine.

As noted above, this final EIA also estimates the economic impact on two additional markets that were not included in the draft analysis: the locomotive and marine diesel transportation service markets. In the NPRM, we proposed to set fuel sulfur standards for locomotive and distillate marine diesel as well as for nonroad diesel fuel. We developed cost estimates for these two types of fuel as well as for nonroad diesel fuel. In the draft EIA, however, we did not consider the economic impacts of these fuel costs on the locomotive and marine sectors separately. Instead, we applied all of these additional fuel costs to the manufacturing application market.

In preparing the final RIA for this rule, we determined that it would be more appropriate to consider the impacts of the fuel program on the diesel marine and locomotive sectors separately. This is because the locomotive and marine markets are directly affected by the higher diesel fuel prices associated with the rule. In addition, production and consumption decisions of downstream end-use markets that use these services are influenced by the prices of transportation services. At the same time, locomotive and marine diesel transportation services are not used solely in the three application markets modeled in the NDEIM. These services are also provided to electric utilities (transporting coal to electric power plants), non-manufacturing service industries (public transportation) and governments. We take this into account and report impacts on those sectors separately.

c. Model Methodology

A detailed description of the model methodology, inputs, and parameters used in this economic impact analysis is provided in Chapter 10 of the Final RIA prepared for this rule. The model methodology is firmly rooted in applied microeconomic theory and was developed following the *OAQPS Economic Analysis Resource Document*.[245]

The NDEIM is a computer model comprised of a series of spreadsheet modules that define the baseline characteristics of the supply and demand for the relevant markets and the relationships between them. The model is constructed based on the market characteristics and inter-connections summarized in this section and described in more detail in Chapter 10 of the RIA. The model is shocked by applying the engineering compliance cost estimates to the appropriate market suppliers, and then numerically solved using an iterative auctioneer approach by "calling out" new prices until a new equilibrium is reached in all markets simultaneously. The output of the model is new equilibrium prices and quantities for all affected markets. This information is used to estimate the social costs of the model and how those costs are shared among affected markets.

The NDEIM uses a multi-market partial equilibrium approach to track changes in price and quantity for the modeled product markets. As explained in the *EPA Guidelines for Preparing Economic Analyses*, "partial" equilibrium refers to the fact that the supply and demand functions are modeled for just one or a few isolated markets and that conditions in other markets are assumed either to be unaffected by a policy or unimportant for social cost estimation. Multi-market models go beyond partial equilibrium analysis by extending the inquiry to more than just a single market. Multi-market analysis attempts to capture at least some of the interactions between markets.[246]

The NDEIM uses an intermediate run time frame. The use of the intermediate run means that some factors of production are fixed and some are variable. This modeling period allows analysis of the economic effects of the rule's compliance costs on current producers. The short run, in contrast, imposes all compliance costs on the manufacturers (no pass-through to consumers), while the long run imposes all costs on consumers (full cost pass-through to consumers). The use of the intermediate run time frame is consistent with economic practices for this type of analysis.

The NDEIM assumes perfect competition in the market sectors. This assumption was questioned by one commenter, who noted that the 25 to 75 hp engine category does not appear to be competitive based on the number of firms in that subsector. Specifically, one

[245] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, *OAQPS Economic Analysis Resource Document*, April 1999. A copy of this document can be found in Docket A–2001–28, Document No. II–A–14.

[246] *EPA Guidelines for Preparing Economic Analyses*, EPA 240–R–00–003, September 2000, p. 125–6.

firm has nearly 29 percent of the market and the top nine firms have about 88 percent. The remaining twelve percent of this market shared among nineteen other firms. While the commenter is correct in noting the limited number of firms in this subsector, we believe it is still appropriate to rely on the perfect competition assumption in this analysis. The perfect competition assumption relies not only on the number of firms in a market but also on other market characteristics. For example, there are no indications of barriers to entry, the firms in these markets are not price setters, and there is no evidence of high levels of strategic behavior in the price and quantity decisions of the firms. In addition, the products produced within each market are somewhat homogeneous in that engines from one firm can be purchased instead of engines from another firm. Finally, according to contestable market theory, oligopolies and even monopolies will behave very much like firms in a competitive market if it is possible to enter particular markets costlessly (*i.e.*, there are no sunk costs associated with market entry or exit). With regard to the nonroad engine market, production capacity is not fully utilized. This means that manufacturers could potentially switch their product line to compete in another segment of the market without a significant investment. For all these reasons, the number of firms in a particular engine submarket does not prevent us from relying on the perfect competition assumption for that submarket. This is true of other engine and equipment subsectors as well. In addition, changing the assumption of perfect competition based on the limited evidence raised by the commenter would break with widely accepted economic practice for this type of analysis.[247]

d. Model Inputs—Elasticities

The estimated social costs of this emission control program are a function of the ways in which producers and consumers of the engines, equipment, and fuels affected by the standards change their behavior in response to the costs incurred in complying with the standards. As the compliance costs ripple through the markets, producers and consumers change their production and purchasing decisions in response to changes in prices. In the NDEIM, these behavioral changes are modeled by the demand and supply elasticities (behavioral-response parameters), which measure the price sensitivity of consumers and producers.

The supply elasticities for the equipment, engine, diesel fuel, and transportation service markets and the demand and supply elasticities for the application markets used in the NDEIM were obtained from peer-reviewed literature sources or were estimated using econometric methods. These econometric methods are well-documented and are consistent with generally accepted econometric practice. Appendix 10H of the RIA contains detailed information on how the elasticities were estimated.

The equipment and engine supply elasticities are elastic, meaning that quantities supplied are expected to be fairly sensitive to price changes. The supply elasticities for the fuel, transportation, and application markets are inelastic or unit elastic, meaning that the quantity supplied/demanded is expected to be fairly insensitive to price changes or will vary one-to-one with price changes. The demand elasticities for the application markets are also inelastic. This is consistent with the Hicks-Allen derived demand relationship, according to which a low cost-share in production combined with limited substitution yields inelastic demand.[248] As noted above, diesel engines, equipment, and fuel represent only a small portion of the total production costs for each of the three application sectors. The limited ability to substitute for these inputs is discussed below.

In contrast to the above, the demand elasticities for the engine, equipment, fuel, and transportation markets are internally derived as part of the process of running the model. This is an important feature of the NDEIM, which allows it to link the separate market components of the model and simulate how compliance costs can be expected to ripple through the affected economic sectors. In the real world, for example, the quantity of nonroad equipment units produced in a particular period depends on the price of engines (the engine market) and the demand for equipment (the application markets). Similarly, the number of engines produced depends on the demand for engines (the equipment market) which depends on the demand for equipment (the application markets). Changes in conditions in one of these markets will affect the others. By designing the model to derive the engine, equipment, transportation market, and fuel demand elasticities, the NDEIM simulates these connections between supply and demand among all the product markets and replicates the economic interactions between producers and consumers.

e. Model Inputs—Fixed and Variable Costs

The EIA treats the fixed costs expected to be incurred by engine and equipment manufacturers differently in the market and social costs analyses. This feature of the model is described in greater detail in Section 10.2.3.3 of the RIA. In the market analysis, estimated engine and equipment market impacts (changes in prices and quantities) are based solely on the expected increase in variable costs associated with the standards. Fixed costs are not included in the market analysis reported in Table VI–F–1 because in an analysis of competitive markets the industry supply curve is based on its marginal cost curve and fixed costs are not reflected in changes in the marginal cost curve. In addition, the fixed costs associated with the rule are primarily R&D costs for design and engineering changes. Firms in the affected industries currently allocate funds for R&D programs and this rule is not expected to lead firms to change the size of their R&D budgets. Therefore, changes in fixed costs for engine and equipment redesign associated with this rule are not likely to affect the prices of engines or equipment. Fixed costs are included in the social cost analysis reported in Table VI–F–2, however, as an additional cost to producers. This is appropriate because even though firms currently allocated funds to R&D those resources are intended for other purposes such as increasing engine power, ease of use, or comfort. These improvements will therefore be postponed for the length of the rule-related R&D program. This is a cost to society.

One commenter recommended that EPA include engine and equipment R&D (fixed) costs in the market analysis. This commenter argued that while in the long run total costs are not determined by changes in fixed costs, total costs are determined initially by both fixed and variable costs. This commenter was concerned that by not including fixed costs, EPA's analysis underestimates the increase in the average price of goods and services produced using engines affected by the rule. In fact, we included

[247] *See*, for example, *EPA Guidelines for Preparing Economic Analyses*, EPA 240–R–00–003, September 2000, p 126. *See also* the Final RIA for this rule, Chapter 10, Section 10.2.3.1.

[248] If the elasticity of demand for a final product is less than the elasticity of substitution between an input and other inputs to the final product, then the demand for the input is less elastic the smaller its cost share. Hicks, J.R., 1961. Marshall's Third Rule: A Further Comment. Oxford Economic Papers 13:262–65; Hicks, J.R., 1963. The Theory of Wages. St. Martins Press, NY, pp. 233–247. *See* Docket A–2001–28, Document No. IV–B–25 for relevant excerpts. *See* Docket A–2001–28, Document No. IV–B–25 for relevant excerpts.

R&D costs in a sensitivity analysis performed for the draft EIA, which has been updated and can be found in Appendix I to Chapter 10 of the Final RIA. Including fixed costs results in a transfer of economic welfare losses from engine and equipment markets to the application markets (engine and equipment producer surplus losses decrease; consumer surplus losses increase), but does not change the overall economic welfare losses associated with the rule.

Unlike for engines and equipment, most of the petroleum refinery fixed costs are for production hardware. Refiners are expected to have to make physical changes to their refineries and purchase additional equipment to produce 500 ppm and then 15 ppm fuel. Therefore, fixed costs are included in the market analysis for fuel price and quantity impacts.

f. Model Inputs—Substitution by Application Suppliers

In modeling the market impacts and social costs of this rule, the NDEIM considers only diesel equipment and fuel inputs to the production of goods in the applications markets. It does not explicitly model alternate production inputs that would serve as substitutes for new nonroad equipment or nonroad diesel fuel. In the model, market changes in the final demand for application goods and services directly correspond to changes in the demand for nonroad equipment and fuel (*i.e.*, in normalized terms there is a one-to-one correspondence between the quantity of the final goods produced and the quantity of nonroad diesel equipment and fuel used as inputs to that production). We believe modeling the market in this manner is economically sound and reflects the general experience for the nonroad market.

Some commenters suggested that the NDEIM should consider substitution to alternate means of production such as pre-buying, delayed buying, extending the life of a current machine, and substituting with different (*e.g.*, gasoline-powered) equipment. These commenters did not provide detailed explanations for their comments or data in support of their substitution arguments. After considering these comments, we conclude that revising the NDEIM to include these effects would be inappropriate.

The term "pre-buying" appears to refer to the possibility that the suppliers in the application market may choose to buy additional unneeded quantities of nonroad equipment prior to the beginning of the Tier 4 program, thus avoiding the higher cost for the Tier 4 equipment. It should be noted that this effect is limited to equipment and does not extend to nonroad diesel fuel. We believe that equipment pre-buying will not be economically viable in most cases due to the cost of holding capital (equipment) idle and of maintaining unused equipment. Such strategic purchases, if they occur at all, would be limited to a period of a few months before the effective date of the standards. The NDEIM models market reactions in the intermediate time frame, beyond the scope of any potential pre-buy. For these reasons, we do not believe it is appropriate to revise the model to include pre-buy as a means of substitution in NDEIM.

"Delayed-buying" appears to refer to the possibility that suppliers in the application market would defer purchasing new equipment initially but would eventually make those purchases. Similarly to pre-buying, this appears to be a short-term effect and would therefore be inappropriate to include in an economic model designed to model the intermediate time frame.

Extending the life of a current machine is suggested as another alternative to purchasing new equipment. We believe this would also be a short term phenomena that is not relevant for the intermediate time frame of the NDEIM. Based on our meetings with equipment users and suppliers, we do not believe that extending the life of nonroad equipment will prove to be an economically viable substitute in the near or long term. Most users of nonroad equipment already extend the life of their equipment to the maximum extent possible and purchase new equipment only when the existing equipment can no longer perform its function, when new demand for production requires additional means for production, or when new equipment offers a cheaper means of production than existing equipment. This situation is not expected to change as a result of this rule. In addition, even if it were possible to extend equipment life even more, this would lower the cost of nonroad equipment as an input to production (because it would be less expensive to maintain old equipment than purchase new equipment) and thus would reduce the economic impact of the Tier 4 program compared to our estimate. For all of the reasons stated here, we have decided not to attempt to model an extended equipment life alternative in the NDEIM.

Finally, some commenters noted that equipment users may chose to substitute with different equipment, particularly gasoline-powered equipment. We believe substitution to gasoline-powered equipment is an alternative only for the smaller power categories (below 75 hp). Based on discussions with equipment manufacturers and users, the dominant reasons for choosing diesel engines over the substantially less expensive gasoline engines include better performance from diesel engines, lower fuel consumption from diesel engines, and the ability to use diesel fuel. The use of diesel fuel is preferable for two reasons: it is safer to store and dispense, and it is compatible with the fuel needed for larger equipment at the same worksite. Where these issues are not a concern, gasoline engines already enjoy a substantial economic advantage over diesel. We do not believe that the incremental increase in new equipment cost associated with this program would provide the necessary economic incentives for switching to gasoline equipment. Equipment users who can use gasoline-fueled equipment already do so, while those who can't due to the high costs of storing and dispensing gasoline fuel already use diesel engines. Therefore, we have not attempted to model the possibility of substitution to gasoline equipment in NDEIM.

g. Model Inputs—Other

Compliance Costs. The NDEIM uses the estimated engine, equipment, and fuel compliance costs described in above and presented in Chapters 6 and 7 of the RIA. Engine and equipment costs vary over time because fixed costs are recovered over five to ten year periods while total variable costs, despite learning effects that serve to reduce costs on a per unit basis, continue to increase at a rate consistent with new sales increases. Similarly, engine operating costs also vary over time because oil change maintenance savings, PM filter maintenance, and fuel economy effects, all of which are calculated on the basis of gallons of fuel consumed, change over time consistent with the growth in nationwide fuel consumption. Fuel-related compliance costs (costs for refining and distributing regulated fuels) also change over time. These changes are more subtle than the engine costs, however, as the fuel provisions are largely implemented in discrete steps instead of phasing in over time. Compliance costs were developed on a ¢/gallon basis; total compliance costs are determined by multiplying the ¢/gallon costs by the relevant fuel volumes. Therefore, total fuel costs increase as the demand for fuel increases. The variable operating costs are based on the natural gas cost of producing hydrogen and for heating diesel fuel for the new desulfurization equipment, and thus would fluctuate along with the price of natural gas.

Operating Savings. Operating savings refers to changes in operating costs that are expected to be realized by users of both existing and new nonroad diesel equipment as a result of the reduced sulfur content of nonroad diesel fuel. These include operating savings (cost reductions) due to fewer oil changes, which accrue to nonroad, marine and locomotive engines that are already in use as well as new nonroad engines that will comply with the standards (*see* Section VI.B). These also include any extra operating costs associated with the new PM emission control technology which may accrue to certain new engines that use this technology. Operating savings are not included in the market analysis because some of the savings accrue to existing engines and because, as explained in Section VI.C.1.c, these savings are not expected to affect consumer decisions with respect to new engines. Operating savings are included in the social cost analysis, however, because they accrue to society. They are added into the estimated social costs as an additional savings to the application and transportation service markets, since it is the users of these engines and fuels who will see these savings. A sensitivity analysis was performed as part of this EIA that includes the operating savings in the market analysis. The results of this sensitivity analysis are presented in Appendix 10.I.

Fuel Marker Costs. Fuel marker costs refers to costs associated with marking high sulfur heating oil to distinguish it from high sulfur diesel fuel produced after 2007 through the use of early sulfur credits or small refiner provisions. Only heating oil sold outside of the Northeast is affected. The higher sulfur NRLM fuel is not allowed to be sold in most of the Northeast, so the marker need not be added in this large heating oil market. These costs are expected to be about $810,000 in 2007, increasing to $1.38 million in 2008, but steadily decreasing thereafter to about $940,000 in 2040 (see Chapter 10 of the RIA). Because these costs are relatively small, they are incorporated into the estimated compliance costs for the fuel program (see discussion of fuel costs, above). They are therefore not counted separately in this economic impact analysis. This means that the costs of marking heating fuel are allocated to all users of the fuel affected by this rule (nonroad, locomotive, and marine) instead of uniquely to heating oil users. This is a reasonable approach since it is likely that refiners will pass the marker costs along their complete nonroad diesel product line and not just to heating oil.

Fuel Spillover. Spillover fuel is highway grade diesel fuel consumed by nonroad equipment, stationary diesel engines, boilers, and furnaces. As described in Section 7.1 of Chapter 7 of the final RIA, refiners are expected to produce more 15 ppm fuel than is required for the highway diesel market. This excess 15 ppm fuel will be sold into markets that allow fuel with a higher sulfur level (*i.e.*, nonroad for a limited period of time, locomotive, marine diesel and heating oil). This spillover fuel is affected by the diesel highway rule and is not affected by this regulation. Therefore, it is important to differentiate between spillover and nonspillover fuel to ensure that the compliance costs for that fuel pool are not counted twice. In the NDEIM, this is done by incorporating the impact of increased fuel costs associated with the highway rule prior to analysis of the final nonroad rule (*see* RIA Section 10.3.8).

Compliance Flexibility Provisions. Consistent with the engine and equipment cost discussion in Section VI.C, the EIA does not include any cost savings associated with the equipment transition flexibility program or the nonroad engine ABT program. As a result, the results of this EIA can be viewed as somewhat conservative.

Locomotive and Marine Fuel Costs. The locomotive and marine transportation sectors are affected by this rule through the sulfur limits on the diesel fuel used by these engines. These sectors provide transportation to the three application markets as well as to other markets not considered in the NDEIM (*e.g.*, public utilities, nonmanufacturing service industries, government). As explained in Section 10.3.1.5 of the RIA, the NDEIM applies only a portion of the locomotive and marine fuel costs to the three application markets. The rest of the locomotive and marine fuel costs are added as a separate item to the total social cost estimates (as Application Markets Not Included in NDEIM).

3. What Are the Results of this Analysis?

Using the revised cost data described earlier in this section and the NDEIM described above and in Chapter 10 of the Final RIA, we estimated the economic impacts of the nonroad engine, equipment and fuel control program. Economic impact results for 2013, 2020, 2030, and 2036 are presented in this section. The first of these years, 2013, corresponds to the first year in which the standards affect all engines, equipment, and fuels. It should be noted that, as illustrated in Table VI–F–3, aggregate program costs peak in 2014; increases in costs after that year are due to increases in the population of engines over time. The other years, 2020, 2030 and 2036, correspond to years analyzed in our benefits analysis. Detailed results for all years are included in the appendices to Chapter 10 of the RIA.

In the following discussion, social costs are computed as the sum of market surplus offset by operating savings. Market surplus is equal to the aggregate change in consumer and producer surplus based on the estimated market impacts associated with the rule. As explained above, operating savings are not included in the market analysis but instead are listed as a separate category in the social cost results tables.

In considering the results of this analysis, it should be noted that the estimated output quantities for diesel engines, equipment, and fuel are not identical to those estimated in the engineering cost described in above and presented in Chapters 6 and 7 of the RIA. The difference is due to the different methodologies used to estimate these costs. As noted above, social costs are the value of goods and services lost by society resulting from: (a) the use of resources to comply with and implement a regulation (*i.e.*, compliance costs); and (b) reductions in output. Thus, the social cost analysis considers both price and output (quantity) effects associated with consumer and producer reaction to increased prices associated with the regulatory compliance costs. The engineering cost analysis, on the other hand, is based on applying additional technology to comply with the new regulations. The engine population in the engineering cost analysis does not reflect consumer and producer reactions to the compliance costs. Consequently, the estimated output quantities from the cost analysis are slightly larger than the estimated output quantities from the social cost analysis.

The results of this analysis suggest that the economic impacts of this rule are likely to be small, on average. Price increases in the application markets are expected to average about 0.1 percent per year. Output decrease in the application markets are expected to average less than 0.02 percent for all years. The price increases for engines, equipment, and fuel are expected to be about 20 percent, 3 percent, and 7 percent, respectively (total impact averaged over the relevant years). The number of engines and equipment produced is expected to decrease by less than 250 units, and the amount of fuel produced annually is expected to decrease by less than 4 million gallons. With respect to the economic welfare analysis, producers and consumers in the application markets are expected to bear about 83 percent of the burden in 2013; this will increase to about 96 percent in 2030 and beyond. In other words, despite the almost total pass-through of costs the average price of goods and services in the application markets is expected to increase by only 0.1 percent. This outcome reflects the fact that diesel engines, equipment, and fuel are only a small part of total costs for the application markets. These results are described in more detail below and in Chapter 10 of the Final RIA.

a. Expected Market Impacts

The estimated market impacts for 2013, 2020, and 2030 are presented in Table VI.F–1. The market-level impacts presented in this table represent production-weighted averages of the individual market-level impact estimates generated by the model: the average expected price increase and quantity decrease across all of the units in each of the engine, equipment, fuel, and final application markets. For example, the model includes seven individual engine markets that reflect the seven different horsepower size categories. The 21.4 percent price change for engines shown in Table VI.F–1 for 2013 is an average price change across all engine markets weighted by the number of production units. Similarly, the equipment impacts presented in Table VI.F–1 are the weighted averages of 42 equipment-application markets, such as small (<25hp) agricultural equipment and large (>600hp) industrial equipment. Note that price increases and quantity decreases for specific types of engines, equipment, application sectors, or diesel fuel markets are likely to be different. The aggregated data presented in this table provide a broad overview of the expected market impacts that is useful when considering the impacts of the rule on the economy as a whole. The individual market-level impacts are presented in Chapter 10 of the Final RIA.[249]

The market impacts of this rule suggest that the overall economic impact of the emission control program on society is expected to be small, on average. According to this analysis, the average prices of goods and services produced using equipment and fuel affected by the rule are expected to increase by about 0.1 percent (as noted above), despite the almost total pass-through of compliance costs to those markets.

Engine Market Results: This analysis suggests that most of the variable costs associated with the rule will be passed along in the form of higher prices. The average price increase in 2013 for engines is estimated to be about 21.4 percent. This percentage is expected to decrease to about 18.3 percent by 2020. In 2036, the last year considered, the average price increase is expected to be about 18.2 percent. This expected price increase varies by engine size because compliance costs are a larger share of total production costs for smaller engines. In 2013, the largest expected percent price increase is for engines between 25 and 50 hp: 29 percent or $850; the average price for an engine in this category is about $2,900. However, this price increase is expected to drop to 22 percent, or about $645, for 2015 and later. The smallest expected percent price increase in 2013 is for engines in the greater than 600 hp category. These engines are expected to see price increases of about 3 percent increase in 2013, increasing to about 7.6 percent in 2015 and then decreasing to about 6.6 percent in 2017 beyond. The expected price increase for these engines is about $2,240 in 2013, increasing to about $6,150 in 2015 and then decreasing to $5,340 in 2017 and later, for engines that cost on average about $80,500.

The market impact analysis predicts that even with these increased in engine prices, total demand is not expected to change very much. The expected average change in quantity is less than 150 engines per year, out of total sales of more than 500,000 engines. The estimated change in market quantity is small because as compliance costs are passed along the supply chain they become a smaller share of total production costs. In other words, firms that use these engines and equipment will continue to purchase them even at the higher cost because the increase in costs will not have a large impact on their total production costs (diesel equipment is only one factor of production for their output of construction, agricultural, or manufactured goods).

Equipment Market Results: Estimated price changes for the equipment markets reflect both the direct costs of the new standards on equipment production and the indirect cost through increased engine prices. In general, the estimated percentage price changes for the equipment are less than that for engines because the engine is only one input in the production of equipment. In 2013, the average price increase for nonroad diesel equipment is estimated to be about 2.9 percent.[250] This percentage is expected to decrease to about 2.5 percent for 2020 and beyond. The range of estimated price increases across equipment types parallels the share of engine costs relative to total equipment price, so the estimated percentage price increase among equipment types also varies. For example, the market price in 2013 for agricultural equipment between 175 and 600 hp is estimated to increase about 1.2 percent, or $1,740 for equipment with an average cost of $143,700. This compares with an estimated engine price increase of about $1,700 for engines of that size. The largest expected price increase in 2013 for equipment is $2,290, or 2.6 percent, for pumps and compressors over 600 hp. This compares with an estimated engine price increase of about $2,240 for engines of that size. The smallest expected price increase in 2013 for equipment is $120, or 0.7 percent, for construction equipment less than 25 hp. This compares with an estimated engine price increase of about $120 for engines of that size.

Again, the market analysis predicts that even with these increased equipment prices total demand is not expected to change very much. The expected average change in quantity is less than 250 pieces of equipment per year, out of a total sales of more than 500,000 units. The average decrease in the quantity of nonroad diesel equipment produced as a result of the regulation is estimated to be about 0.02 percent for all years. The largest expected decrease in quantity in 2013 is 18 units of construction equipment per year for construction equipment between 100 and 175 hp, out of about 63,000 units. The smallest expected decrease in quantity in 2013 is less than

[249] The NDEIM distinguishes between "merchant" engines and "captive" engines. "Merchant" engines are produced for sale to another company and are sold on the open market to anyone who wants to buy them. "Captive" engines are produced by a manufacturer for use in its own nonroad equipment line (this equipment is said to be produced by "integrated" manufacturers). The market analysis for engines includes compliance costs for merchant engines only. The market analysis for equipment includes equipment compliance costs plus a portion of the engine compliance costs attributable to captive engines.

[250] It should be noted that the equipment prices used in this analysis reflect current market conditions. An increase in equipment prices associated with the nonroad Tier 3 standards would reduce size of the percentage increase in price. In this sense, our Economic Impact Analysis is conservative as it is based on the impact of the Tier 4 program on Tier 1 and Tier 2 equipment prices and therefore overestimates the market impacts of the Tier 4 program.

one unit per year in all hp categories of pumps and compressors.

It should be noted that the absolute change in the number of engines and equipment does not match. This is because the absolute change in the quantity of engines represents only engines sold on the market. Reductions in engines consumed internally by integrated engine/equipment manufacturers are not reflected in this number but are captured in the cost analysis.

TABLE VI.F–1.—SUMMARY OF MARKET IMPACTS ($2002)

Market	Engineering cost	Change in price		Change in quantity	
	Per unit	Absolute ($million)	Percent	Absolute	Percent
2013					
Engines	$1,052	$821	21.4	[a] −79	−0.014
Equipment	1,198	975	2.9	−139	−0.017
Loco/Marine Transp [b]			0.009		−0.007
Application Markets [b]			0.097		−0.015
No. 2 Distillate Nonroad	0.06	0.07	6.0	[c] −2.75	−0.019
2020					
Engines	950	761	18.3	[a] −98	−0.016
Equipment	1,107	976	2.5	−172	−0.018
Loco/Marine Transp [b]			0.001		−0.008
Application Markets [b]			0.105		−0.017
No. 2 Distillate Nonroad	0.07	0.07	7.0	[c] −3.00	−0.021
2030					
Engines	937	751	18.2	[a] −114	−0.016
Equipment	968	963	2.5	−200	−0.018
Loco/Marine Transp [b]			0.010		−0.008
Application Markets [b]			0.102		−0.016
No. 2 Distillate Nonroad	0.07	0.07	7.0	[c] −3.53	−0.022
2036					
Engines	931	746	18.2	[a] −124	−0.016
Equipment	962	956	2.5	−216	−0.018
Loco/Marine Transp [b]			0.010		−0.008
Application Markets [b]			0.101		−0.016
No. 2 Distillate Nonroad	0.07	0.07	7.0	[c] −3.85	−0.022

Notes:

[a] The absolute change in the quantity of engines represents only engines sold on the market. Reductions in engines consumed internally by integrated engine/equipment manufacturers are not reflected in this number but are captured in the cost analysis. For this reason, the absolute change in the number of engines and equipment does not match.

[b] The model uses normalized commodities in the application markets because of the great heterogeneity of products. Thus, only percentage changes are presented.

[c] Units are in million of gallons.

Transportation Market Results: The estimated price increase associated with the proposed standards in the locomotive and marine transportation markets is negligible, at 0.01 percent for all years. This means that these transportation service providers are expected to pass along nearly all of their increased costs to the agriculture, construction, and manufacturing application markets, as well as other application markets not explicitly modeled in the NDEIM. This price increases represent a small share of total application market production costs, and therefore are not expected to affect demand for these services.

Application Market Results: The estimated price increase associated with the new standards in all three application markets is very small and averages about 0.1 percent for all years. In other words, on average, the prices of goods and services produced using the affected engines, equipment, and fuel are expected to increase negligibly. This results from the observation that compliance costs passed on through price increases represent a very small share of total production costs in all the application markets. For example, the construction industry realizes an increase in production costs of approximately $580 million in 2013 because of the price increases for diesel equipment and fuel. However, this represents less than 0.001 percent of the $820 billion value of shipments in the construction industry in 2000. The estimated average commodity price increase in 2013 ranges from 0.08 percent in the manufacturing application market to about 0.5 percent in the construction market. The percentage change in output is also estimated to be very small and averages less than 0.02 percent for all years. Note that these estimated price increases and quantity decreases are average for these sectors and may vary for specific subsectors. Also, note that absolute changes in price and quantity are not provided for the application markets in Table VI.F–1 because normalized commodity values are used in the market model. Because of the great heterogeneity of manufactured or agriculture products, a normalized commodity ($1 unit) is used in the application markets. This has no impact on the estimated percentage change impacts but makes interpretation of the absolute changes less informative.

Fuel Markets Results: The estimated average price increase across all nonroad diesel fuel is about 7 percent for all years. For 15 ppm fuel, the estimated price increase for 2013 ranges from 5.6 percent in the East Coast region (PADD 1&3) to 9.1 percent in the mountain region (PADD 4). The average national output decrease for all fuel is estimated to be about 0.02 percent for all years, and is relatively constant across all four regional fuel markets.

b. Expected Economic Welfare Impacts

Estimated social costs are presented in Table VI.F–2. In 2013, the total social costs are projected to be about $1,510 million ($2002). About 83 percent of the total social costs is expected to be borne by producers and consumers in the application markets in 2013, indicating that the majority of the compliance costs associated with the rule are expected to be passed on in the form of higher prices. When these estimated impacts are broken down, about 58.5 percent of the social costs are expected to be borne by consumers in the application markets and about 41.5 percent are expected to be borne by producers in the application markets. Equipment manufacturers are expected to bear about 9.5 percent of the total social costs. Engine manufacturers and diesel fuel refineries are expected to bear 2.8 percent and 0.5 percent, respectively. The remaining 4.2 percent of the social costs is expected to be borne by the locomotive and marine transportation service sector. In this last sector, about 97 percent of the gross decrease in market surplus is expected to be borne by the application markets that are not included in the NDEIM but that use these services (*e.g.*, public utilities, nonmanufacturing service industries, government) while about 3 percent is expected to be borne by locomotive and marine service providers. Because of the way the NDEIM is structured, with the fuel savings added separately, the results imply that locomotive and marine service provider would see net benefits from the rule due to the operating savings associated with low sulfur fuel. In fact, they are likely to pass along some or all of those operating savings to the users of their services, reducing the size of the welfare losses for those users.

Total social costs continue to increase over time and are projected to be about $2,046 million by 2030 and $2,227 million in 2036 ($2002). The increase is due to the projected annual growth in the engine and equipment populations. Producers and consumers in the application markets are expected to bear an even larger portion of the costs, approximately 96 percent. This is consistent with economic theory, which states that, in the long run, all costs are passed on to the consumers of goods and services.

The present value of total social costs through 2036, contained in Table VI.F–3, is estimated to be $27.2 billion ($2002). This present value is calculated using a social discount rate of 3 percent from 2004 through 2036. We also performed an analysis using a 7 percent social discount rate. Using that discount rate, the present value of the social costs through 2036 is estimated to be $13.9 billion ($2002). As shown in Table VI.F–3, these results suggest that total engineering costs exceed compliance costs by a small amount. This is due primarily to the fact that the estimated output quantities for diesel engines, equipment, and fuel are not identical to those estimated in the engineering cost analysis, which is due to the different methodologies used to estimate these costs (*see* previous discussion in this Section IV.F.3).

TABLE VI.F–2.—SUMMARY OF SOCIAL COSTS ESTIMATES ASSOCIATED WITH PRIMARY PROGRAM 2015, 2020, 2030, AND 2036

[2002, $Million][a, b]

	Market surplus ($10⁶)	Operating savings ($10⁶)	Total	Percent
2013				
Engine Producers Total	$42.0		$42.0	2.8
Equipment Producers Total	143.1		143.1	9.5
Construction Equipment	64.0		64.0	
Agricultural Equipment	51.8		51.8	
Industrial Equipment	27.2		27.2	
Application Producers & Consumers Total	1,496.7	($243.2)	1,253.5	83.0
Total Producer	620.9			41.5
Total Consumer	875.7			58.5
Construction	584.3	($115.2)	469.2	
Agriculture	430.0	($78.2)	351.8	
Manufacturing	482.4	($49.8)	432.5	
Fuel Producers Total	8.0		8.0	0.5
PADD I&III	4.1		4.1	
PADD II	3.3		3.3	
PADD IV	0.0		0.0	
PADD V	0.6		6.0	
Transportation Services, Total	104.9	($41.5)	63.4	4.2
Locomotive	1.6	($12.4)	($10.8)	
Marine	0.9	($9.9)	($9.0)	
Application markets not included in NDEIM	102.4	($19.2)	$83.2	
Total	1,794.7	($284.7)	$1,510.0	100.0%
2020				
Engine Producers Total	0.1		0.1	0.0
Equipment Producers Total	122.7		122.7	6.7
Construction Equipment	57.8		57.8	
Agricultural Equipment	39.7		39.7	

TABLE VI.F–2.—SUMMARY OF SOCIAL COSTS ESTIMATES ASSOCIATED WITH PRIMARY PROGRAM 2015, 2020, 2030, AND 2036—Continued

[2002, $Million][a, b]

	Market surplus ($10[6])	Operating savings ($10[6])	Total	Percent
Industrial Equipment	25.2		25.2	
Application Producers & Consumers Total	1,826.1	($192.3)	1,633.8	89.4
Total Producer	762.2			41.7
Total Consumer	1,063.8			58.3
Construction	744.0	($91.1)	653.0	
Agriculture	524.3	($61.8)	462.5	
Manufacturing	557.8	($39.4)	518.3	
Fuel Producers Total	11.2		11.2	0.6
PADD I&III	5.6		5.6	
PADD II	4.6		4.6	
PADD IV	0.2		0.2	
PADD V	0.8		0.8	
Transportation Services, Total	95.7	($35.1)	60.6	3.3
Locomotive	2.0	($7.2)	($5.2)	
Marine	1.1	($11.6)	($10.5)	
Application markets not included in NDEIM	92.6	($16.3)	76.3	
Total	2,055.7	($227.4)	$1,828.3	100.0%
2030				
Engine Producers Total	0.1		0.1	0.0
Equipment Producers Total	5.9		5.9	0.3
Construction Equipment	4.0		4.0	
Agricultural Equipment	1.9		1.9	
Industrial Equipment	0.1		0.1	
Application Producers & Consumers Total	2,112.3	($154.2)	1,958.1	95.7
Total Producer	882.2			41.7
Total Consumer	1,230.1			58.3
Construction	863.8	($73.0)	790.8	
Agriculture	606.8	($49.6)	557.2	
Manufacturing	641.6	($31.6)	610.0	
Fuel Producers Total	13.2		13.2	0.6
PADD I&III	6.7		6.7	
PADD II	5.2		5.2	
PADD IV	0.3		0.3	
PADD V	1.0		1.0	
Transportation Services, Total	109.1	($39.9)	69.2	3.4
Locomotive	2.5	($7.8)	($5.3)	
Marine	1.4	($13.6)	($12.2)	
Application markets not included in NDEIM	105.2	($18.5)	86.7	
Total	2,240.6	($194.1)	$2,046.4	100.0%
2036				
Engine Producers Total	0.2		0.2	0.0
Equipment Producers Total	6.4		6.4	0.3
Construction Equipment	4.3		4.3	
Agricultural Equipment	2.0		2.0	
Industrial Equipment	0.1		0.1	
Application Producers & Consumers Total	2,287.4	($155.7)	2,131.7	95.7
Total Producer	955.5			41.7
Total Consumer	1,331.9			58.3
Construction	936.4	($50.0)	862.7	
Agriculture	657.8	($73.7)	607.8	
Manufacturing	693.2	($31.9)	661.3	
Fuel Producers Total	14.5		14.5	0.7
PADD I&III	7.3		7.3	
PADD II	5.8		5.8	
PADD IV	0.3		0.3	
PADD V	1.0		1.0	
Transportation Services, Total	116.9	($42.6)	74.3	3.3
Locomotive	2.8	($8.2)	($5.4)	
Marine	1.6	($14.6)	($13.0)	
Application markets not included in NDEIM	112.5	($19.8)	92.7	

TABLE VI.F–2.—SUMMARY OF SOCIAL COSTS ESTIMATES ASSOCIATED WITH PRIMARY PROGRAM 2015, 2020, 2030, AND 2036—Continued

[2002, $Million][a, b]

	Market surplus ($10⁶)	Operating savings ($10⁶)	Total	Percent
Total	$2,425.3	($198.4)	$2,227.0	100.0

Notes: [a] Figures are in 2002 dollars.
[b] Operating savings are shown as negative costs.

TABLE VI.F–3.—NATIONAL ENGINEERING COMPLIANCE COSTS AND SOCIAL COSTS ESTIMATES FOR THE RULE (2004–2036)

[$2002; $Million]

Year	Engineering compliance costs	Total social costs
2004	0	0
2005	0	0
2006	0	0
2007	($17)	($18)
2008	54	54
2009	54	54
2010	328	327
2011	923	922
2012	1,305	1,304
2013	1,511	1,510
2014	1,691	1,690
2015	1,742	1,741
2016	1,743	1,743
2017	1,763	1,762
2018	1,778	1,778
2019	1,795	1,795
2020	1,829	1,828
2021	1,816	1,815
2022	1,819	1,818
2023	1,844	1,843
2024	1,858	1,857
2025	1,888	1,887
2026	1,921	1,920
2027	1,954	1,952
2028	1,985	1,984
2029	2,017	2,016
2030	2,047	2,046
2031	2,078	2,077
2032	2,108	2,107
2033	2,139	2,137
2034	2,169	2,167
2035	2,198	2,197
2036	2,228	2,227
NPV at 3%	27,247	27,232
NPV at 7%	13,876	13,868

VII. Alternative Program Options Considered

Our final emission control program for nonroad engines and equipment consists of a two-step program to reduce the sulfur content of nonroad diesel fuel in conjunction with Tier 4 engine standards. The rule also contains limits on sulfur levels in locomotive and marine diesel fuel. As described in the draft Regulatory Impact Analysis for the proposal, we evaluated a number of alternative options with regard to the scope, level, and timing of the standards. This section presents a summary of those alternative program options and our reasons for either adopting or not adopting these options.

A. Summary of Alternatives

For our Notice of Proposed Rulemaking (NPRM), we developed emissions, benefits, and cost analyses for a number of alternative program options involving variations in both the fuel and engine programs. The alternatives we considered can be categorized according to the structure of their fuel requirements: whether the 15 ppm fuel sulfur limit for nonroad diesel fuel is reached in two steps, like the program we are finalizing today, or in one step. Within each of these two broad fuel program categories, we considered a number of different engine programs. This section summarizes the alternatives. A more detailed description of the alternatives can be found in the NPRM and the draft RIA.

One-step alternatives were those in which the 15 ppm fuel sulfur standard for nonroad diesel fuel is applied in a single step. We evaluated three one-step alternatives, summarized in table VII–1. Option 1 represented an engine program that was similar to that in our proposed program, the primary difference being the generally earlier phase-in dates for the PM standards. We considered the Option 1 engine program as being the most stringent one-step program that could be considered even potentially feasible considering cost, lead-time, and other factors. Option 1 also included a June 2008 start date for the 15 ppm sulfur standard applicable to nonroad diesel fuel and the 500 ppm sulfur standard applicable to locomotive and marine fuel. We also considered two other one-step alternatives which differ from Option 1. As described in table VII–1, Option 1b differed from Option 1 regarding the timing of the fuel standards, while Option 1a differed from Option 1 in terms of the engine standards. Options 1a and 1b also differed from Option 1 by extending the 15 ppm fuel sulfur limit to locomotive and marine diesel fuel.

Two-step alternatives were those in which the nonroad diesel fuel sulfur standard was set first at 500 ppm and then was reduced to 15 ppm. The two-step alternatives varied from the proposed program in terms of both the timing and levels of the engine standards and the timing of the fuel standards. Option 2a was the same as the proposed program except the 500 ppm fuel standard was introduced a year earlier, in 2006. Option 2b was the same as the proposed program except the 15 ppm fuel standard was introduced a year earlier (in 2009) and the trap-based PM standards began earlier for all engines. Option 2c was the same as the proposed program except the 15 ppm fuel standard was introduced a year earlier in 2009 and the trap-based PM standards began earlier for engines 175–750 hp. Option 2d was the same as the proposed program except the NO_X standard was reduced to 0.30 g/bhp-hr for engines of 25–75 hp, and this standard was phased in. Finally, Option 2e was the same as the proposed program except there were no new Tier 4 NO_X limits.

In the NPRM, option 3 was identical to the proposed program, except that it would have exempted mining equipment over 750 hp from the Tier 4 standards. We explained in detail in section 12.6.2.2.7 of the draft RIA that we had very serious reservations regarding the legality of this option given these engines' high emission rates of PM, NO_X and NMHC and the availability of further emissions control at reasonable cost. We adhere to these conclusions here. We do note, however, that we are adopting somewhat different provisions for this engine category than we proposed. As explained in sections II.A. and II.B above, although we have adopted aftertreatment-based PM standards for these engines, the standards are slightly higher than those proposed to assure their technical feasibility. We also have deferred a decision on whether to adopt aftertreatment-based standards for NO_X for mobile machines with engines greater than 750 hp. We also have provided ample lead time for these engines to comply with the Tier 4 standards, both in terms of the rule's compliance dates (which include a 2015 date for the final Tier 4 standards, one year later than we proposed) and the ABT and equipment manufacturer flexibilities. This lead time takes into account the long design periods, high cost, and low sales volumes of these engines. Thus, although we strongly disagree with the option of not adopting Tier 4 standards for these engines, we do recognize their need for unique standards and compliance dates.

Option 4 included applying the 15 ppm sulfur limit to both locomotive and marine diesel fuel in addition to nonroad fuel. On the basis of comments received and additional analyses, we have determined that a 15ppm sulfur standard for locomotive and marine fuel is appropriate, though we have included certain options for utilization of off-specification fuel and transmix not represented in our original Option 4. This aspect of our final program is discussed in detail in section IV.

Options 5a and 5b were identical to the proposed program except with respect to standards for engines less than 75 hp. Option 5a was identical to the proposed program except that no new program requirements would be set in Tier 4 for engines under 75 hp. Instead, Tier 2 standards and testing requirements for engines under 50 hp, and Tier 3 standards and testing requirements for 50–75 hp engines, would continue indefinitely. The Option 5b program was identical to the proposed program except that for engines under 75 hp only the 2008 engine standards would be set, *i.e.* there would be no additional PM filter-based standard in 2013 for 25–75 hp engines, and no additional NO_X + NMHC standard in 2013 for 25–50 hp engines. We are not adopting Options 5a or 5b in today's action. As explained at 8.2.3 of the Summary and Analysis of Comments, and in sections 12.6.2.2.9 and 12.6.2.2.10 of chapter 12 of the draft RIA, these options would forego substantial PM and NO_X + NMHC emission reductions (on the order of hundreds of thousands of tons of each pollutant) which are feasible at reasonable cost. We note further that many of these smaller engines operate in populated areas and in equipment without closed cabs—in mowers, small construction machines, and the like—where personal exposures to toxic emissions (both PM and air toxics which are part of the NMHC fraction) may be pronounced well beyond what is indicated simply by a comparison of nationwide emissions inventory estimates. We would also emphasize the remarkable growth in recent sales and usage for these smaller diesel machines, and we expect this trend to continue, pointing up the need for effective PM emissions control from these engines. We thus do not see a basis in law or policy to adopt either of these options.

In response to comments on our NPRM we also investigated a number of other variations in the engine standards as we developed our final rule. These variations were generally related to the phase-in of engine standards in a number of different horsepower categories. A discussion of these variations is provided in section II as well as in various background documents.

Table VII–1 contains a summary of a number of these alternatives. The expected emission reductions, costs, and monetized benefits associated with them in comparison to the proposed program were evaluated for the NPRM. Those analyses were not revised for this final rulemaking to reflect changes in our empirical models or assumptions. We received no new information that would cause us to believe that the relative impacts and differences for those alternative program options relative to our final program would change enough to make an impact on our assessments of the feasibility or appropriateness of the options. The remainder of this section will summarize some of the comments we received on the options and our responses to those comments.

TABLE VII–1.—SUMMARY OF ALTERNATIVE PROGRAM OPTIONS

Option	Fuel Standards	Engine Standards[a]
	Final program	
	• 500 PPM in 2007 for NR, loco/marine • 15 ppm in 2010 for NR • 15 ppm in 2012 for loco/marine	• <75 hp: PM standards in 2008 • 25–75 hp: PM AT-based standards in 2013 • 75–175 hp: PM AT-based standards in 2012 • 175–750 hp: PM AT-based standards in 2011 • 75–175 hp: NO_X AT-based standards phase-in 2012–2014 • 175–750 hp: NO_X AT-based standards phase-in 2011–2014 • >750 hp: PM and NO_X AT phased-in 2011 and 2015
	1-Step Fuel Options	
1	• 15 ppm in 2008 for NR and loco/marine	• <50 hp: PM stds only in 2009 • 25–75 hp: PM AT stds and EGR or equivalent NO_X technology in 2013; no NO_X AT • >75 hp: PM AT stds phasing in beginning in 2009; NO_X AT phasing in beginning in 2011
1a	• 15 ppm in 2008 for NR, loco/marine	• PM AT introduced in 2009–10 • NO_X AT introduced in 2011–12
1b	• 15 ppm in 2006 for NR, loco/marine	Same as 1a
	2-Step Fuel Options	
2a	Same as proposed program except— • 500 ppm in 2006 for NR, loco/marine.	Same as proposed program
2b	Same as proposed program except— • 15 ppm in 2009 for NR and loco/marine	Same as proposed program except— • Move PM AT up 1 year for all engines >25 hp (phase in starts 2010)
2c	Same as proposed program except— • 15 ppm in 2009 for NR and loco/marine	Same as proposed program except— • Move PM AT up 1 year for all engines 175–750 hp (phase in starts 2010)
2d	• Same as proposed program	Same as proposed program except—

TABLE VII–1.—SUMMARY OF ALTERNATIVE PROGRAM OPTIONS—Continued

Option	Fuel Standards	Engine Standards [a]
		• Phase-in NO_X AT for 25–75hp beginning in 2013
Other Options		
3	• Same as proposed program	Same as proposed program except— • Mining equipment over 750 hp left at Tier 2
4	Same as proposed program except— • Downgrade flexibilities for loco/marine not included.	Same as proposed program
5a	• Same as proposed program	Same as proposed program except— • No Tier 4 standards <75 hp
5b	• Same as proposed program	Same as proposed program except— • No new <75hp standards after 2008 (i.e., no CDPFs in 2013)

Notes: [a] AT = aftertreatment.

B. Introduction of 15 ppm Nonroad Diesel Sulfur Fuel in One Step

EPA carefully evaluated an alternative which would require that the nonroad diesel sulfur level be reduced to 15ppm in a single step, beginning June 1, 2008. The one-step fuel options, including the three variations Option 1, Option 1a, and Option 1b, were presented and discussed in detail in the NPRM and in the draft RIA.

Many comments were received about a one step diesel fuel sulfur control approach taking effect in 2008. Refiners commented that they did not think that they could reduce both the highway and nonroad diesel fuel pools down to 15 ppm in the same timeframe while maintaining the supply of these two diesel fuel pools. The refiners went on to say that having a 500 ppm outlet for off-specification material in the nonroad diesel fuel pool is critical in the years after reducing the highway diesel fuel pool to 15 ppm to ensure supply of highway fuel. The refining industry further commented that the one step program would provide fewer environmental benefits and also provide the refining industry less time and flexibility to make the transition to the 15 ppm sulfur level for nonroad diesel fuel compared to a two step approach. While many environmental organizations and the Engine Manufacturers Association (EMA) commented that they preferred a 15 ppm standard as soon as possible, EMA also pointed out that a quick transition to 500 ppm would provide important fleet-wide emission reductions, reduce maintenance costs and enable the use of certain emission control technology such as exhaust gas recirculation and oxidation catalysts. Commenters generally said little about the engine standards associated with the one-step options, other than to point out that earlier introduction of 15 ppm sulfur fuel means that aftertreatment-based standards and nonroad engine retrofits can also be introduced earlier.

The reasons provided in the NPRM for choosing the two step program over the one-step program still apply and generally address the comments received (*see* section 12.6.2 of the draft RIA). Although there would be greater PM and NO_X emission reductions with the one-step approach due to earlier introduction of aftertreatment technology enabled by the 15 ppm sulfur diesel fuel, the SO_2 emission benefits for the two-step approach are greater due to the earlier adoption of the 500 ppm sulfur standard. Thus, even assuming that the one-step approach would not jeopardize implementation of the highway diesel emission rule, the emission impacts of these two options are mixed. Moreover, the costs for achieving the second step (15 ppm) of the two step approach are likely to be lower than under the one step approach. This is because advanced desulfurization technologies are much more likely to be used in 2010 after additional testing and demonstration, while they may hardly be considered at all if they would have to be installed for 2008. One advanced desulfurization technology, Process Dynamics Isotherming, is expected to lower the cost of complying with the 15 ppm step by about one cent per gallon. This cost discrepancy is expected to persist since it is associated with the investment of significant capital which cannot be modified or replaced without significant additional expense. Additionally, under the two step program, refiners will be able to use their experience in complying with 15 ppm highway diesel fuel sulfur standard to better design their nonroad hydrotreaters needed for 2010.

After careful consideration of these matters, we have decided to finalize the two-step approach in today's action.

C. Applying the 15 ppm Sulfur Cap to Locomotive and Marine Diesel Fuel

In the NPRM, we requested comment on extending the 15 ppm cap to locomotive and marine diesel fuel in 2010 or some later year as part of this rule. The costs and inventory impacts of this alternative were explored in the context of Option 4 in the NPRM. A 15ppm sulfur cap for locomotive and marine fuel would increase the long-term PM and SO_2 benefits of the rule and would reduce the number of fuels being carried in the distribution system after 2014, when the small refiner provisions of this rule expire. It would also allow refiners to plan to comply with the 15 ppm cap for locomotive and marine diesel fuel at the same time as they plan to comply with the 500 ppm cap for NRLM fuel and the 15 ppm cap for nonroad fuel.

As a result of comments received and additional analyses performed since the NPRM, we are finalizing a 15 ppm sulfur cap for locomotive and marine fuel in today's notice. A full discussion of the feasibility and benefits of a 15 ppm sulfur cap for locomotive and marine fuel can be found in section IV, along with a summary of the comments we received and our responses to those comments. In addition, we are planning a separate rule to implement new emission standards for locomotive and marine diesel engines that will build upon the 15 ppm sulfur standard applicable to fuel used by these engines. We are publishing an Advanced Notice of Proposed Rulemaking in another section of today's **Federal Register** describing our plans in this area.

D. Other Alternatives

We also analyzed a number of other alternatives in the NPRM, as summarized in table VII–1. Some of these focused on control options more stringent than our final program while others reflect modified engine requirements that result in less stringent control. In the NPRM we presented our assessment of these options in terms of the feasibility, emission reductions, costs, and other relevant factors. Few comments were received on these other alternatives, and no new information arose to alter what we believe are significant concerns with respect to these Options compared to the final program. Hence, with the exception of the few alternative program elements that we did incorporate into our final program as described earlier in this section, we did not include these options into our final program. Our detailed responses to all the comments received on the other alternatives can be found in section 8 of the Summary and Analysis of Comments document.

VIII. Future Plans

The above discussion describes the contents of this final rule. This section addresses a variety of areas not addressed by this rule. In these several areas, we expect to continue our efforts to improve our compliance programs and achieve further reductions in emissions from nonroad engines.

A. Technology Review

As we described in sections III.E and G of the proposal, there are some technology issues that warrant our planning a future review of emissions control technology for engines under 75 hp. Under our implementation schedule presented in section II.A, standards based on the use of PM filter technology will take effect in the 2013 model year for 25–75 hp engines (or in the 2012 model year for manufacturers opting to skip the transitional standards for 50–75 hp engines). However, at this time we have not decided what long-term PM standards for engines under 25 hp are appropriate. No PM filter-based standards are being adopted for these under 25 hp engines in this final rule. Likewise, we have not decided what the long-term NO_X standards for engines under 75 hp should be, and no NO_X adsorber-based standards are being set for these engines in this final rule. As part of the technology review, we plan to thoroughly evaluate progress made toward applying advanced PM and NO_X control technologies to these smaller engines.

We plan to conduct the technology review in 2007, and to conclude it by the end of that year, to give manufacturers lead time should an adjustment in the program be considered appropriate. We do not intend to include in the technology review a reassessment of PM filter technology needed to meet the optional 0.02 g/hp-hr PM standard for 50–75 hp engines in 2012. We assume that manufacturers would only choose this option if they had confidence that they could meet the 0.02 g/hp-hr standard in 2012, a year earlier than otherwise required.

Numerous commenters expressed support for the planned technology review. MECA and STAPPA/ALAPCO stressed that the review should not be limited to considering the need to relax PM filter-based standards for small engines, but should also consider technology innovations that would justify increasing the stringency of small engine standards that are not currently aftertreatment-based. This is indeed our intent. Yanmar suggested that the review be deferred to 2010 or later, because NO_X control experience from highway diesels will not be sufficient by 2007. On the contrary, based on the rate of technology development progress to date for highway engines, we believe that there will be a very large amount of pertinent new information available by 2007, even though widespread field experience may be lacking. Waiting longer to conduct the technology review would, we believe, provide insufficient leadtime to the industry should an adjustment to the 2013 standards be found appropriate. Some engine and equipment manufacturers called for expanding the technology review to other power categories. As discussed in the proposal, we do not believe that a generalized technology review of the sort being conducted for the heavy-duty highway engine program is warranted, primarily due to the very fact that the nonroad standards are modeled on the highway program, and the highway program does include this comprehensive review. We also do not see the specific technical issues for engines above 75 hp that have been identified for smaller engines, such as might warrant our expanding the review at this time. Engine manufacturers also expressed interest in a consultative process in the near future that would establish the scope, outputs, and criteria for the review, possibly including assigning responsibility for the review to an independent entity. Although we plan and hope to have the active participation of all interested parties in the review process, assigning responsibility for the review to groups or individuals outside the Agency would be inappropriate. As the review would be closely tied to potential subsequent rulemaking action by the Agency, it is essential that it adequately cover the relevant issues. To ensure this, it is imperative that we retain overall responsibility for the review. We have not yet worked out process details for the review, but will do so at some later date.

Several commenters strongly stressed the need for EPA to work with governmental standards-setting bodies in other countries to harmonize future standards. As discussed in section II.A.8, we recognize the importance of harmonizing nonroad diesel standards and have worked diligently with our colleagues responsible for setting such standards outside the U.S., thus far with good success. The March 2004 Directive that sets future nonroad diesel standards in the European Union (EU) will very closely align the EU program with our program in the Tier 4 timeframe.[251] Further enhancing prospects for close harmonization, the Directive includes plans for a future technical review: "There are still some uncertainties regarding the cost effectiveness of using after-treatment equipment to reduce emissions of particulate matter (PM) and of oxides of nitrogen (NO_X). A technical review should be carried out before 31 December 2007 and, where appropriate, exemptions or delayed entry into force dates should be considered."

Note that the timing for this review coincides with that of our own planned review. Among other things, both our review and the EU review will consider the appropriate long-term standards for engines between 25 and 50 hp, engines for which we have set PM-filter based standards and for which the EU has not. Furthermore, in addition to re-evaluating the standards, the EU technical review will consider the need to introduce standards for engines below 25 hp and above 750 hp, the two categories for which the EU has not yet set emission standards, and for which harmonization is thus most lacking. We are greatly encouraged by the degree of harmonization achieved thus far, and, given our common interests, issues and planned timing, expect to work closely with Commission staff in carrying out the 2007 technology review, with an aim of preserving and enhancing harmonization of standards.

In response to comments received on the proposal, we wish to clarify that the technology review for engines under 75 hp will be a comprehensive undertaking that may result in adjustments to standards, implementation dates, or other provisions (such as flexibilities) in either direction (that is, toward more or less stringency), depending on conclusions reached in the review about

[251] Council of the European Union, ≥Directive of the European Parliament and of the Council amending Directive 97/68/EC,≥ March 15, 2004.

appropriate standards under the Clean Air Act. All relevant factors including technical feasibility and commercial viability of engines and machines designed to meet the standards will be taken into account.

B. Test Procedure Issues

Section III describes two issues related to test procedures that warrant further attention in the future. First, we are adopting transient test procedures for engines subject to Tier 4 emission standards, but we intend to collect data that would help us adopt a duty cycle that would appropriately test constant-speed engines. Second, we are adopting cold-start test procedures, but are interested in collecting additional data that could be used to revise those procedures if appropriate.

C. In-Use Testing

Although this final rule does not include an in-use testing program for nonroad diesel engines, we expect to establish such a program for the future in a separate rulemaking action. The goal of this program will be to ensure that emissions standards are met throughout the useful life of the engines, under conditions normally experienced in-use. The Agency expects to pattern the in-use testing requirements for nonroad diesel engines after a program that is being developed for heavy-duty diesel highway vehicles. This program will be funded and conducted by the manufacturer's of heavy-duty diesel highway engines with our oversight. We expect it will incorporate a two-year pilot program. The pilot program will allow the Agency and manufacturers to gain the necessary experience with the in-use testing protocols and generation of in-use test data using portable emission measurement devices prior to fully implementing program. A similar pilot program is expected to be part of any manufacturer-run, in-use NTE test program for nonroad engines.

The Agency plans to promulgate the in-use testing requirements for heavy-duty highway vehicles in the December 2004 time frame. We anticipate proposing a manufacturer-run, in-use testing program for nonroad diesel engines by 2005 or earlier. As mentioned above, the nonroad diesel engine program is expected to be patterned after the heavy-duty highway program.

D. Engine Diagnostics

We are also in the process of defining diagnostic requirements that would apply to highway diesel engines. Once we have adopted requirements for highway engines, we would aim to adapt the requirements as needed to appropriately address diagnostic needs for nonroad diesel engines. These programs would likely be very similar, but the diagnostics for nonroad engines my need to differ in some ways, depending on the technologies used by different types and sizes of engines and on an assessment of an appropriate level of information and control for engines used in nonroad applications.

E. Future NO_X Standards for Engines in Mobile Machinery Over 750 hp

In section II.A.4, we explain that we are not, at this time, setting Tier 4 NO_X standards for mobile machinery over 750 hp based on the performance of high-efficiency aftertreatment, although we note that the 2.6 g/bhp-hr NO_X standard taking effect for these engines in 2011 represents a more than 60% NO_X reduction from the 6.9 g/bhp-hr Tier 1 level in effect today, and a more than 40% reduction from the 4.8 g/bhp-hr NO_X+NMHC Tier 2 standard level that takes effect in 2006. We are still evaluating the issues involved for these engines to achieve a more stringent NO_X standard, and believe that these issues are resolvable. We intend to continue evaluating the appropriate long-term NO_X standard for mobile machinery over 750 hp and expect to announce further plans regarding these issues, perhaps as early as 2007.

F. Emission Standards for Locomotive and Marine Diesel Engines

This final rule adopts limited requirements to limit sulfur levels in distillate fuels used in locomotive and many marine diesel engines, which will help reduce PM emissions from these engines. In an upcoming rulemaking, we will consider an additional tier of NO_X and PM standards for marine diesel engines less than 30 liters per cylinder and for locomotive engines. These standards would reflect the application of advanced emission-control technology, including the potential to use the high-efficiency catalytic emission-control devices like those described elsewhere in this preamble. In developing these new standards, we will consider the substantial overlap in engine technology between the locomotive and marine engines and the nonroad engines covered by this final rule. We will also take into account the unique features associated with locomotive and marine engines (and their respective markets) and the extent to which these differences may constrain the feasibility of applying advanced emission control technologies to those engines.

We are concurrently publishing an Advance Notice of Proposed Rulemaking that describes the emission-control program we are contemplating for these engines. After consideration of comments submitted on the Advance Notice, we will publish a Notice of Proposed Rulemaking. Our proposal will be subject to comment before its expected completion in the 2006 time frame.

The engine emission control program to be described in the Advance Notice will cover all locomotive engines subject to 40 CFR part 92 and all marine diesel engines with displacement below 30 liters per cylinder. Note that the rule will therefore cover marine diesel engines below 37 kW, which are currently regulated through Tier 3 with land-based nonroad engines in 40 CFR part 89. The rule will also address both recreational and commercial marine diesel engines with displacement below 30 liters per cylinder. Marine engines at or above 30 liters per cylinder typically use a different kind of fuel, residual fuel, and will be considered in a separate rulemaking to be finalized by April 27, 2007, pursuant to a regulatory provision adopted in our recent rule setting standards for those engines (68 FR 9783, February 28, 2003).

G. Retrofit Programs

In the proposal, we requested comment on setting voluntary new engine emission standards applicable to the retrofit of nonroad diesel engines. As described in section III.A, we are not adopting a retrofit credit program with today's action. We believe it is important to more fully consider the details of a retrofit credit program and work with interested parties in determining whether a viable program can be developed. EPA intends to explore the possibility of a voluntary nonroad retrofit credit program through future action.

H. Reassess the Marker Specified for Heating Oil

As discussed in sections IV and V, we are requiring that the chemical marker solvent yellow 124 (SY–124) be added to heating oil outside of the Northeast/Mid-Atlantic Area. We received comments from the American Society of Testing and Materials (ASTM), the Coordinating Research Council (CRC), the Department of Defense (DoD), and the Federal Aviation Administration (FAA) requesting that we delay finalizing the selection of a specific marker for use in this final rule due to concerns for jet fuel contamination. ASTM withdrew its request for a postponement in the regulation, given that this final rule requires addition of the marker at the terminal, rather than the refinery gate as proposed. This eliminates most of the concern regarding jet fuel contamination. However, ASTM stated that some concern remains regarding jet fuel contamination downstream of the terminal. Nevertheless, ASTM related that these concerns need not delay finalization of the marker requirements in this rule, since a CRC program to evaluate these concerns is expected to be completed well before SY–124 must be added to heating oil. FAA is also undertaking an effort to identify fuel markers that would be compatible for use in jet fuel.

We also received comments from the heating oil industry and the Department of Defense, which expressed concerns regarding the potential health effects and maintenance impacts on heating oil equipment from the use of SY–124 in heating oil. As discussed in section V, we believe these concerns have been adequately addressed for us to specify the use of SY–124 in this final rule. The EU has required the use of SY–124 in heating oil since August 2002. The EU intends to re-evaluate the use of SY–124 after December 2005 or earlier if they learn of any health, safety, or environmental concerns from their in-use experience with SY–124.

We will keep abreast of the ASTM, CRC, FAA, IRS, and EU activities and commit to a review of our use of SY–124 under today's rule based on these findings. If alternative markers are identified that do not raise concerns regarding the potential contamination of jet fuel, we will initiate a rulemaking to evaluate the use of one of these markers in place of SY–124.

IX. Public Participation

Many interested parties provided their input on the proposed rulemaking during our public comment period. This comment period, along with the three public hearings that were held in New York, Chicago, and Los Angeles, provided ample opportunity for public participation. Throughout the rulemaking process, EPA met with stakeholders including representatives from the fuel refining and distribution industry, engine and equipment manufacturing industries, emission control manufacturing industry, environmental organizations, states, agricultural interests, and others.

A detailed Response to Comments document was prepared for this rulemaking that describes the comments that we received on the proposal along with our response to each of these comments. The Response to Comments document is available in the air docket and e-docket for this rule, as well as on the Office of Transportation and Air Quality homepage. In addition, comments and responses for many key issues are included throughout this preamble.

X. 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 the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of this Executive Order. The Executive Order defines a "significant regulatory action" as any regulatory action that is likely to result in a rule that may—

- 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;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

A final Regulatory Impact Analysis has been prepared and is available in the docket for this rulemaking and at the internet address listed under "How Can I Get Copies of This Document and Other Related Information?" above. This action was submitted to the Office of Management and Budget for review under Executive Order 12866. Estimated annual costs of this rulemaking are estimated to be $2 billion per year, thus this proposed rule is considered economically significant. Written comments from OMB and responses from EPA to OMB comments are in the public docket for this rulemaking.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them. The OMB control number for engine-related information collection is 2060–0460 (EPA ICR number 1897.07) and for fuel-related information collection is 2060–0308 (EPA ICR number 1718.07).

We will use the engine-related information to ensure that new nonroad diesel engines comply with emission standards through certification requirements and various subsequent compliance provisions. This information collection is mandatory under the provisions of 42 U.S.C. 7401–7671(q). We will use the fuel-related information to ensure that diesel fuel meets the sulfur limits and corresponding requirements related to marking and segregating the different types and grades of diesel fuel. This information collection is mandatory under the provisions of 42 U.S.C. 7545(c), (g) and (i), and 7625–1.

In addition, this notice announces OMB's approval of the information collection requirements for other programs, as summarized in Table X.B–1.

TABLE X.B–1—APPROVED INFORMATION COLLECTION REQUESTS FROM OTHER PROGRAMS

Program	Final rule cite	OMB control number	EPA ICR number	OMB approval
Nonroad spark-ignition engines over 19 kW	November 8, 2002 (67 FR 68242).	2060–0460	1897.04	January 31, 2003.
Recreational vehicles	November 8, 2002 (67 FR 68242).	2060–0460	1897.04	January 31, 2003.
Rebuilders of various types of engines	November 8, 2002 (67 FR 68242).	2060–0104	0783.46	June 11, 2003.
Highway motorcycles	January 15, 2004 (69 FR 2398).	2060–0104	0783.46	March 26, 2004.

The estimated annual public reporting and recordkeeping burden for collecting information from all these programs is shown in Table X.B–2. 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.

TABLE X.B–2.—INFORMATION COLLECTION BURDENS

Engine type	Respondents	Hours per respondent	Hours for all respondents	Capital costs for all respondents	Operating and maintenance costs for all respondents	Total costs for all respondents
Nonroad diesel engine manufacturers	75	3,304	247,783	$0	$5,894,802	$18,661,614
Diesel fuel suppliers	2,615	75	196,288	1,800,000	1,800,000	18,371,600
Nonroad spark-ignition engine manufacturers	12	1,832	21,986	174,419	2,507,790	3,617,683
Recreational vehicle manufacturers	39	684	26,669	1,627,907	2,137,115	4,869,253
Highway motorcycles	46	32	1,449	0	23,686	79,428
Importers	40	13	529	0	150,000	169,223
Rebuilders	200	6	1,200	0	0	38,800

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. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule. EPA received various comments on the rulemaking provisions covered by the ICRs, but no comments on the paperwork burden or other information in the ICRs. All comments that were submitted to EPA are considered in the relevant Summary and Analysis of Comments, which can be found in the docket. A copy of any of the submitted ICR documents may be obtained from Susan Auby, Collection Strategies Division, U.S. Environmental Protection Agency (2822–T), 1200 Pennsylvania Ave., NW., Washington, DC 20460 or by e-mail at *auby.susan@epa.gov.*

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 a public docket for this rule, which includes this ICR, under Docket ID number OAR–2003–0012. Submit any comments related to the ICR for this rule to EPA and OMB. Address comments to OMB by e-mail to *drostker@omb.eop.gov* or fax to (202) 395–7285. Please do not send comments to OMB via U.S. Mail.

C. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

EPA has decided to prepare a Regulatory Flexibility Analysis (RFA) in connection with this final rule. For purposes of assessing the impacts of today's rule on small entities, a small entity is defined as: (1) A small business that is primarily engaged in the manufacturing of nonroad diesel engines and equipment that meets the definitions based on the Small Business Administration's (SBA) size standards (*see* table X.C.–1 below); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE X.C–1.—SMALL BUSINESS ADMINISTRATION SIZE STANDARDS FOR VARIOUS BUSINESS CATEGORIES

Industry	Defined as small entity by SBA if:	Major SIC[a] Codes
Engine manufacturers	Less than 1,000 employees	Major Group 35.
Equipment manufacturers:		
—Construction equipment	Less than 750 employees	Major Group 35.
—Industrial truck manufacturers (*i.e.* forklifts)	Less than 750 employees	Major Group 35.
—All other nonroad equipment manufacturers	Less than 500 employees	Major Group 35.
Fuel refiners	Less than 1500 employees[b]	2911.
Fuel distributors	<varies>	<varies>

Notes:
[a] Standard Industrial Classification.
[b] EPA has included in past fuels rulemakings a provision that, in order to qualify for the small refiner flexibilities, a refiner must also have a company-wide crude refining capacity of no greater than 155,000 barrels per calendar day. EPA has included this criterion in the small refiner definition for a nonroad diesel sulfur program as well.

Pursuant to 5 U.S.C. 603, EPA prepared an Initial Regulatory Flexibility Analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel (SBAR Panel, or "the Panel") to obtain advice and recommendations of representatives of the regulated small entities pursuant to 5 U.S.C. 609(b) (*see* 68 FR 28518–28521, May 23, 2003). A detailed discussion of the Panel's advice and recommendations can be found in the Panel Report (Docket A–2001–28, Document No. II–A–172). *See also* section III.C above.

We have also prepared a Regulatory Flexibility Analysis for today's rule. The Regulatory Flexibility Analysis addresses the issues raised in public comments on the IRFA, which was part of the proposal of this rule. The Regulatory Flexibility Analysis is available for review in the docket and is summarized below. The key elements of a regulatory flexibility analysis include—

—The need for, and objectives of, the rule;
—The significant issues raised by public comments, a summary of the Agency's assessment of those issues, and a statement of any changes made to the proposed rule as a result of those comments;
—The types and number of small entities to which the rule will apply;
—The reporting, recordkeeping and other compliance requirements of the rule; and
—The steps taken to minimize the impact of the rule on small entities, consistent with the stated objectives of the applicable statute.

1. Need for and Objectives of the Rule

Controlling emissions from nonroad engines and equipment, in conjunction with controls on sulfur concentrations in diesel fuel, has very significant public health and welfare benefits, as explained in section I of this preamble. We are finalizing new engine standards and related provisions under sections 213(a)(3) and (4) of the Clean Air Act which, among other things, direct us to establish (and from time to time revise) emission standards for new nonroad diesel engines. Similarly, section 211(c)(1) authorizes EPA to regulate fuels if any emission product of the fuel causes or contributes to air pollution that may endanger public health or welfare, or that may impair the performance of emission control technology on engines and vehicles. We are finalizing new fuel standards today for both of these reasons.

2. Summary of Significant Public Comments on the IRFA

We received comments from engine and equipment manufacturers, fuel refiners, fuel distributors and marketers, and consumers during the public comment period following the proposal of this rulemaking. All of the following comments were taken into account in developing today's final rule. Responses to these comments are located in subsection 5 below, along with the description of the provisions that we are finalizing to reduce the rule's impact on small businesses. More detailed information in response to these comments can be found in sections III.C. (Engine and Equipment Small Business Provisions) and IV.B (Hardship Relief Provisions for Qualifying Refiners) of this preamble. Additional detail may also be found in the Final Regulatory Flexibility Analysis, located in the Regulatory Impact Analysis, as well as in the Summary and Analysis of Comments for this final rule.

a. Public Comments Received on Engine and Equipment Standards

One small engine manufacturer commented that the proposed provisions for small business engine manufacturers are appropriate and strongly supported their inclusion in the final rule. The manufacturer raised many concerns of why it believes that it is necessary to include provisions, such as: Larger/higher-volume manufacturers will have priority in supply of new technologies and will have more R&D time to complete development of these systems before they are available to smaller manufacturers; smaller manufacturers do not command the same amount of attention from potential suppliers of critical technologies for Tier 4 controls, and are thus concerned that they may not be able to attract a manufacturer to work with them on the development of compliant technologies. This small manufacturer believes that the additional three-year time period proposed for small engine manufacturers in the NPRM is necessary for the company, and is their estimate of the time that it will take for these technologies to be available to small engine manufacturers.

The Small Business Administration's Office of Advocacy ("Advocacy") raised the concern that the rule would impose significant burdens on a substantial number of small entities producing engines of 75 hp or less, with little corresponding environmental benefit. Advocacy therefore recommended that PM standards for engines in the 25–75 hp range not be based on performance of aftertreatment technologies. Advocacy believed that the proposed flexibilities will not suffice on their own to appropriately minimize the regulatory burdens on small entities; and Advocacy noted that during the SBREFA process some small equipment manufacturers stated that although EPA would allow some equipment to be sold which would not require new emissions controls, engine manufacturers would not produce or sell such equipment. Advocacy also commented that we have not shown that substantial numbers of small businesses have taken advantage of previous small business flexibilities, or that small businesses would be able to take advantage of the flexibilities under this rule. Lastly, Advocacy commented that although full compliance with the more stringent emissions controls requirements would be delayed for small manufacturers, small business manufacturers eventually will be required to produce equipment meeting the new requirements.

b. Public Comments Received on Fuel Standards

i. General Comments on Small Refiner Flexibility

One small refiner commented that it is not feasible at this time to evaluate the impact of the three fuels regulations on the refining industry (and small refiners), however it stated that we should continue to evaluate the impacts and act quickly to avoid shortages and price spikes and we should be prepared, if necessary, to act quickly in considering changes in the regulations to avoid these problems. We also received comment that some small refiners that produce locomotive and marine fuels fear that future sulfur reductions to these markets could be very damaging.

ii. Comments on the Small Refiner Definition

A small refiner commented that the proposed redefinition of a small refiner (to not grandfather as small refiners those that were small for highway diesel) would both negate the benefits afforded under the small refiner provisions in the Highway Diesel Sulfur rule and disqualify its status as a small refiner. The small refiner is, however, in support of the addition of the capacity limit in the small refiner definition which will correct the problem of the inadvertent loop-hole in the two previous fuel rules. Though the refiner is concerned that the wording of the proposed language may result in small refiners such as itself, who grew by normal business practice, being disqualified as small refiners. The refiner suggested that we clarify the language and include provisions for continuance of small refiner flexibility for refiners who qualified under the Highway Diesel Sulfur rule (and have not been disqualified as the result of a merger or acquisition).

iii. Comments on the Baseline Approach

A coalition of small refiners provided comments on a few aspects of concern. The small refiners believe that the fuel segregation, and ensuing marking and dying, provisions are quite complex. One small refiner believes that mandating a minimum volume of NRLM production would conflict with the purpose of maintaining adequate on-highway volumes of 15 ppm sulfur fuel and unnecessarily restricts small refiners, and offered suggestions in their comments on how to improve the language. In addition, the small refiner believes that mandating a minimum volume of NRLM production would conflict with the purpose of maintaining adequate on-highway volumes of 15 ppm sulfur fuel and unnecessarily restricts small refiners, and offered suggestions in their comments on how to improve the language.

iv. Comments on Small Refiner "Option 4"

A coalition of small refiners commented that if the final rule is not issued before January 1, 2004, a provision should be made to accommodate those small refiners planning to take advantage of the proposed small refiner "Option 4" (the NRLM/Gasoline Compliance option). A small refiner echoed the concerns of the small refiner coalition, commenting that delayed finalization of the final rule would undermine the benefits of small refiner flexibility Option 4. The small refiner is concerned that a delay in issuing the rule, and subsequent delay in the opportunity to apply the interim gasoline flexibility, would negate its opportunity to take full advantage of the credits the refiner now has, as it would not be able to comply with the 300 ppm cap. The small refiner suggested that we allow small refiners to apply for temporary relief and operate under the Option 4 provision. Another small refiner commented that, in the NPRM, it was unclear if a small refiner could elect to use any or all of the first three of the small refiner provisions if it did not elect to use Option 4. Further, the refiner understood that if Option 4 was chosen, a small refiner could not use any of the first three options. The refiner believes that it is important that a small refiner be able to use Options 1, 2, and 3 in combination with each other, and stated that we need to clarify the intent in the final rule. The small refiner also commented that the provisions in 40 CFR 80.553 and 80.554 are not clear and should be revised to clarify their intent. Specifically, the refiner questioned whether or not a small refiner who committed to producing ULSD by June 1, 2006 in exchange for an extension of its interim gasoline sulfur standards (under 40 CFR 80.553) could elect to exercise the options allowed under 40 CFR 80.554.

A small refiner raised the concern that the small refiner Option 4 only provides an adjustment to those small refiners whose small refiner gasoline sulfur standards were established through the hardship process of 40 CFR 80.240. The small refiner suggested that we finalize a compliance option that allows a 20 percent increase in small refiner gasoline sulfur standards be extended to all small refiners, not just those with standards established pursuant to 40 CFR 80.240(a), and offers suggested language in its comments.

v. Comments on Emission Impacts of the Small Refiner Provisions

A state environmental group commented that the provisions for small refiners raise substantial environmental concerns. The group is concerned that these provisions will allow small refiners the ability to produce gasoline with an unknown sulfur content for an unknown length of time; this fuel may then be sold at the refiner's retail outlet, and may become the primary fuel for some vehicles, which alters vehicle fleet emissions performance. This environmental group also commented that the absence of any process of notification regarding small business provisions to notify States of these provisions is troubling. The concern is that these deviations from fuel content that affects fuels consumed in states that use emissions inventories for air quality planning purposes, and can significantly alter inventories. The group suggested that in the future there should be greater communication from us regarding decisions that impact the quality of fuels consumed in a state, and thus impact the quality of that state's air.

Another state environmental group commented on the flexibility provisions for small refiners; the group is concerned that the exemption will not have a minor effect on the nation's fuel supply, as the state is an intermountain western state. The group comments that the impact of this exemption is concentrated in these states, namely Washington and Oregon—states which are served primarily by refineries that will be allowed to delay compliance with the ULSD standards until 2014. Therefore, the group commented, residents of these areas are denied air quality benefits equivalent to those promised the rest of the country. Those seeking to purchase and use equipment in these areas will be subject to the ULSD standard regardless of fuel supply and availability in their area, would be faced with misfueling, deferring purchase of new equipment, or paying a premium for a "boutique" fuel.

vi. Comments on Inclusion of a Crude Capacity Limit for Small Refiners and Leadtime Afforded for Mergers and Acquisitions

A non-small refiner supported the inclusion of the 155,000 bpcd limit, but suggested that we limit the provision of affording a two-year leadtime to small refiners who lose their small status due to merger or acquisition to the case where a small refiner merges with another small refiner. Further, the refiner commented that it would be inappropriate to allow such small refiners to be able to generate credits for "early" production of lower sulfur diesels during this two-year leadtime. Lastly, the refiner commented that a small refiner which acquires a non-small refiner, and thus loses its small refiner status, should not be eligible for hardship provisions. Another commenter stated that if we were to finalize the 155,000 bpcd limit, we should not apply it in cases of a merger between two small refiners. The commenter further stated that a merger of two small companies in a hardship condition does not imply improved financial health in the same way that an acquisition would. Another non-small refiner commented that it supports the two-year lead time for refineries that lose their status as a small refiner; the refiner believes that any refiner with the financial wherewithal to acquire additional refineries to allow its crude capacity to exceed 155,000 bpcd should not be able to retain status as a small refiner.

vii. Necessity of Small Refiner Program

A non-small refiner provided comment on the NPRM stating the belief that the proposed provisions for small refiners are not practical. The refiner is concerned that having provisions for small refiners adds a level of complication, results in emissions losses, increases the potential for ULSD contamination, and create an unfair situation in the marketplace. Similarly, another non-small refiner and a trade group representing many refiners and others in the fuels industry commented that they oppose the extension of compliance deadlines for small refiners, as this can result in inequitable situations that may affect the refining industry for some time and can put the distribution system at risk for contamination of lower sulfur fuels. They further stated that all refiners will face challenges in complying with the upcoming standards and would not significantly alter the business decisions that small refiners would make. They also stated that non-small refiners face similar issues with their older and/or smaller refineries, but will not have the benefit of being able to postpone making these decisions as small refiners will.

viii. Comments on Fuel Marker

We received comments from terminal operators stating that the proposed heating oil marker requirements would force small terminal operators to install expensive injection equipment and that they would not be able to recoup the costs.

3. Types and Number of Small Entities

The small entities directly regulated by this final rule are nonroad diesel engine and equipment manufacturers, nonroad diesel fuel refiners, and nonroad diesel fuel distributors and marketers. These categories are described in more detail below, and the definitions of small entities in those categories are listed in table X.C–1 above.

a. Nonroad Diesel Engine Manufacturers

Before beginning the SBREFA process, EPA conducted an industry profile for the nonroad diesel sector. We have not received any new information since that time and we continue to believe that this is a valid characterization of the industry. Using information from the industry profile, EPA identified a total of 61 engine manufacturers. The top 10 engine manufacturers comprise 80 percent of the total market, while the other 51 companies make up the remaining 20 percent.[252] Of the 61 manufacturers, four fit the SBA definition of a small entity. These four manufacturers were Anadolu Motors, Farymann Diesel GMBH, Lister-Petter Group, and V & L Tools (parent company of Wisconsin Motors LLC, formerly "Wis-Con Total Power"). These businesses comprised eight percent of the total nonroad engine sales for the year 2000.

b. Nonroad Diesel Equipment Manufacturers

We also used the industry profile to determine the number of nonroad small business equipment manufacturers. EPA identified over 700 manufacturers with sales and/or employment data that could be included in the screening analysis. These businesses included manufacturers in the construction, agricultural, mining, and outdoor power equipment (mainly, lawn and garden equipment) sectors of the nonroad diesel market. The equipment produced by these manufacturers ranged from small walk-behind equipment (sub-25 hp engines) to large mining and construction equipment (using engines in excess of 750 hp). Of the manufacturers with available sales *and* employment data (approximately 500 manufacturers), nonroad small business equipment manufacturers represent 68 percent of total nonroad equipment manufacturers (and these manufacturers accounted for 11 percent of nonroad diesel equipment industry sales in 2000).

c. Nonroad Diesel Fuel Refiners

Our current assessment is that 26 refiners (collectively owning 33 refineries) meet SBA's definition of a small business for the refining industry. The 33 refineries appear to meet both the employee number and production volume criteria mentioned above. These small refiners currently produce approximately 6 percent of the total high-sulfur diesel fuel. It should be noted that because of the dynamics in the refining industry (*e.g.*, mergers and acquisitions), the actual number of refiners that ultimately qualify for small refiner status under the nonroad diesel sulfur program could be different than this assessment.

d. Nonroad Diesel Fuel Distributors and Marketers

The industry that transports, distributes, and markets nonroad diesel fuel encompasses a wide range of businesses, including bulk terminals, bulk plants, fuel oil dealers, and diesel fuel trucking operations, and totals thousands of entities that have some role in this activity. Over 90 percent of these entities meet small entity criteria. Common carrier pipeline companies are also a part of the distribution system; 10 of them are small businesses.

4. Reporting, Recordkeeping and Other Compliance Requirements

This section describes the expected burden of the compliance requirements (for all manufacturers and refiners) for the standards being finalized in today's action.

a. Nonroad Diesel Engine and Equipment Manufacturers

For engine and equipment standards, we must have the assurance that engines and/or equipment produced by manufacturers meet the applicable standard, and will continue to meet this standard as the equipment passes through to the ultimate end user. We are continuing many of the reporting, recordkeeping, and compliance requirements prescribed for nonroad engines and equipment, as set out in 40 CFR part 89. These include, certification requirements and reporting of production, emissions information, use of transition provisions, etc. The types of professional skills required to prepare reports and records are also similar to the types of skills that were needed to meet the regulatory requirements set out in 40 CFR part 89. Key differences in the requirements of today's rule as related to 40 CFR part 89 are the additional testing and defect reporting. We are finalizing an increase in the number of data points (*i.e.*, transient testing) that will be required for reporting emissions information. Also, as proposed, we are requiring additional defect reporting for Tier 4 and later engines. We are requiring that manufacturers report to us if they learn that a substantial number of their engines have emission-related defects. This is generally not a requirement to collect information; however if manufacturers learn that there are or might be a substantial number of emission-related defects, then they must send us information describing the defects.

b. Nonroad Diesel Fuel Refiners, Distributors, and Marketers

For any fuel control program, we must have the assurance that fuel produced by refiners meets the applicable standard, and that the fuel continues to meet this standard as it passes downstream through the distribution system to the ultimate end user. This is particularly important in the case of diesel fuel, where the aftertreatment technologies expected to be used to meet the engine standards are highly sensitive to sulfur. Many of the recordkeeping, reporting and compliance provisions of the today's action are fairly consistent with those in place today for other fuel programs,

[252] All sales information used for this analysis was 2000 data.

including the current 15 ppm highway diesel regulation. For example, recordkeeping involves the use of product transfer documents, which are already required under the 15 ppm highway diesel sulfur rule (40 CFR 80.560). Under today's final rule we are adding additional recordkeeping and reporting requirements for refiners, importers, and fuel distributors to implement the designate and track provisions. However, interactions with parties from all segments of the distribution system indicated that the records necessary were analogous to records already kept as a normal process of doing business. Consequently, the only significant additional burden would be associated with the reporting requirement.

General requirements for reporting for refiners and importers include: registration (only in the case where a refiner or importer is not registered under a previous fuel program), pre-compliance reports (on a refiner or importer's progress towards meeting the nonroad diesel fuel requirements as specified in this rule), quarterly designation reports, and annual reports. All parties from the refiner to the terminal will be required to report volumes of designated fuels received and distributed, as well as compliance with quarterly and annual limits. All parties in the distribution system are required to keep product transfer documents (PTDs), though refiners and importers are required to initially generate and provide information on commercial PTDs that identify the diesel fuel with meeting specific needs (*i.e.*, 15 ppm highway diesel, 500 ppm highway diesel, etc.). Also, refiners in Alaska and small refiner/credit fuel users must report end users of their fuel. These end users must also keep records of these fuel purchases. Lastly, small refiners are required to apply for small refiner status and small refiner baselines.

In general, we are requiring that all records be kept for at least five years. This recordkeeping requirement should impose little additional burden, as five years is the applicable statute of limitations for current fuel programs.

See section X.B, above, for a discussion of the estimated burden hours and costs of the recordkeeping and reporting that will be required by this final rule. Detailed information on the reporting and recordkeeping measures associated with this rulemaking are described in the Information Collection Requests (ICRs) for this rulemaking—1897.05 for nonroad diesel engines, and 1718.05 for fuel-related items.

5. Regulatory Alternatives To Minimize Impact on Small Entities

Below we discuss the Panel recommendations, EPA proposals, and final regulatory alternatives to minimize the rule's impact on small entities. More detailed information on the provisions for these entities can be found in sections III.C and IV.B of this preamble (for small business engine and equipment manufacturers and small entities throughout the fuel distribution system, respectively).

a. Panel Recommendations

During the SBREFA process, the Panel recommended transition flexibilities that we considered during the development of the NPRM. The Panel recommended provisions for both the one-step and two-step options. Since we are finalizing a two-step approach, only the recommendations for this approach are being discussed here. (A complete discussion of all of the Panel recommendations and our proposals for small entities is located in section X.C. of the NPRM.)

Following the SBREFA process, the Panel (or some Panel members), recommended the following transition flexibilities and hardship provisions to help mitigate the impacts of the rulemaking on small entities. We proposed and requested comment on these recommendations in the NPRM.

i. Panel Recommendations for Small Business Engine Manufacturers

For nonroad diesel small business engine manufacturers, we proposed the following provisions:

• A manufacturer must have certified in model year 2002 or earlier and would be limited to 2500 units per year to be eligible for all provisions set out below;

• For PM—

—Small engine manufacturers could delay compliance with the standards for up to three years for engines under 25 hp, and those between 75 and 175 hp (as these engines only have one standard)

—small engine manufacturers have the option to delay compliance for one year if interim standards are met for engines between 50 and 75 hp (for this power category we are treating the PM standard as a two phase standard with the stipulation that small manufacturers cannot use PM credits to meet the interim standard; also, if a small manufacturer elects the optional approach to the standard (elects to skip the interim standard), no further relief will be provided)

• for NO_X [253]

—A three year delay in the program for engines in the 25–50 hp and the 75–175 hp categories, consistent with the one-phase approach recommendation above;

• A small engine manufacturer could be afforded up to two years of hardship (in addition to the transition flexibilities) upon demonstrating to EPA a significant hardship situation;

• Small engine manufacturers would be able to participate in an averaging, banking, and trading (ABT) program (which we proposed as part of the overall rulemaking program for all manufacturers);

• Engines under 25 hp would not be subject to standards based on use of advanced aftertreatment; and,

• No NO_X aftertreatment-based standards for engines 75 hp and under.

ii. Panel Recommendations for Small Business Equipment Manufacturers

We proposed the following provisions for nonroad diesel small business equipment manufacturers:

• Small business nonroad diesel equipment manufacturers must have reported equipment sales using certified engines in model year 2002 or earlier to be eligible for all provisions;

• Essential continuance of the transition flexibilities offered for the Tier 1 and Tier 2 nonroad diesel emission standards (40 CFR 89.102), which are available to all nonroad diesel equipment manufacturers

—'Percent-of-production allowance'—over seven model-year period manufacturers may install engines not certified to the new emission standards in an amount of equipment equivalent to 80 percent of one year's production, implemented by power category with the average determined over the period in which the flexibility is used (this proposal would afford additional flexibility over the comparable flexibility in Tier 2/3, however, because of the smaller number of horsepower categories in the Tier 4 rule)

—'Small volume allowance'—a manufacturer may exceed the 80 percent allowance in seven years as described above, provided that the previous Tier engine use does not exceed 700 total over seven years, and 200 in any given year, limited to one family per power category; alternatively, at the manufacturer's choice by horsepower category, a

[253] There is no change in the NO_X standard for engines under 25 hp and those between 50 and 75 hp. For these two power bands EPA proposed no special provisions.

program that eliminates the "single family provision" restriction with revised total and annual sales limits as shown below:

≤175 hp: 525 previous Tier engines (over 7 years) with an annual cap of 150 units (separate for each hp category)

>175 hp: 350 previous Tier engines (over 7 years) with an annual cap of 100 units (separate for each hp category);

- Small business equipment manufacturers would be allowed to borrow from the Tier 3/Tier 4 flexibilities for use in the Tier 2/Tier 3 time frame; and,
- Small business equipment manufacturers could be afforded up to two years of hardship after other transition allowances are exhausted, similar to that offered small business engine manufacturers.

In addition, we proposed the Panel's recommendation that the provisions for small equipment manufacturers be extended to all equipment manufacturers, regardless of size. We also sought comment on the total number of engines and annual cap values proposed and on implementing the small volume allowance provision without a limit on the number of engine families.

iii. Panel Recommendations for Small Refiners, Distributors, and Marketers

The following provisions were proposed for nonroad diesel small refiners:

- Small refiners would be required to use 500 ppm sulfur fuel beginning June 1, 2010 and 15 ppm fuel beginning June 1, 2014;
- Small refiners may choose one of the following transition provisions, which serve to encourage early compliance with the diesel fuel sulfur standards:

—Credits for Early Desulfurization: would allow small refiners to generate and sell credits for nonroad diesel fuel that meets the small refiner standards earlier than required in the regulation; or,

—Limited Relief on Small Refiner Interim Gasoline Sulfur Standards: a small refiner producing its entire nonroad diesel fuel pool at 15 ppm sulfur by June 1, 2006, and who chooses not to generate nonroad credits for early compliance, would receive a 20 percent relaxation in its assigned small refiner interim gasoline sulfur standards (with the maximum per-gallon sulfur cap for any small refiner remaining at 450 ppm); and,

- A small refiner would be afforded hardship similar to the provisions established under 40 CFR 80.270 and 80.560 (the gasoline sulfur and highway diesel fuel sulfur programs, respectively), case-by-case approval of hardship applications must be sought based on demonstration of extreme hardship circumstances.

We did not propose specific provisions for nonroad diesel fuel distributors and marketers in the NPRM. During the SBREFA process, distributors commented that they would support a one-step approach to eliminate the possibility of having multiple grades of fuel in the distribution system and the Panel recommended that we further study this issue during the development of the rule.

iv. Additional Panel Recommendations

Some, but not all, Panel members recommended that the following provisions be included in the NPRM; we requested comment on these items but did not propose them:

- The inclusion of a technological review of the standards in the 2008 time frame
- No PM aftertreatment-based standards for engines between 25 and 75 hp

b. Discussion of Items Being Finalized in Today's Action

i. Provisions for Small Business Engine Manufacturers

For nonroad diesel small business engine manufacturers, we are finalizing many of the provisions set out above with some significant revisions, as described below. We are finalizing all of the hardship provisions that we proposed. We believe these provisions are an element of providing appropriate lead time for this class of engines.

For engines under 25 hp:

- PM—a manufacturer may elect to delay compliance with the standard for up to three years.
- NO_X—there is no change in the existing NO_X standard for engines in this category, so no special provisions are being provided.

For engines in the 25 to 50 hp category:

- PM—manufacturers must comply with the interim standards (the Tier 4 requirements that begin in model year 2008) on time, and may elect to delay compliance with the 2013 Tier 4 requirements (0.02 g/bhp-hr PM standard) for up to three years.
- NO_X—a manufacturer may elect to delay compliance with the standard for up to three years.

For engines in the 50 to 75 hp category:

- PM—A small business engine manufacturer may delay compliance with the 2013 Tier 4 requirement of 0.02 g/bhp-hr PM for up to three years provided that it complies with the interim Tier 4 requirements that begin in model year 2008 on time, without the use of credits (as manufacturers of engines in this category still have the option to comply with the Tier 3 standard). Alternatively, a manufacturer may elect to skip the interim standard completely. Manufacturers choosing this option will receive only one additional year for compliance with the 0.02 g/bhp-hr standard (*i.e.* compliance in 2013, rather than 2012).
- NO_X—there is no change in the NO_X standard for engines in this category, therefore no special provisions are being provided.

For engines in the 75 to 175 hp category:

- PM—a manufacturer may elect to delay compliance with the standard for up to three years.
- NO_X—a manufacturer may elect to delay compliance with the standard for up to three years.

In regard to the Office of Advocacy's concern regarding the technical feasibility of PM and NO_X aftertreatment devices, as proposed in the NPRM, we are not adopting standards based on performance of NO_X aftertreatment technologies for engines under 75 hp. We believe the factual record—as documented in the RIA, the Summary and Analysis of Comments, and this preamble—does not support the claim that the PM standards will not be technically feasible in 2013 for the 25–75 hp engines. As set out at length in section 4.1.3 of the RIA, among other places, performance of PM traps is not dependent on engine size.

We disagree with the statement made by the Office of Advocacy that, based on available information, we do not have a sufficient basis for engines between 25 and 75 hp to be subject to PM standards based on use of advanced aftertreatment. As we have documented earlier and in the RIA, we believe that such standards are feasible for these engines at reasonable cost,[254] and will help to improve very important air quality problems, especially by reducing exposure to diesel PM and by aiding in attainment of the PM 2.5 National

[254] As the cost issues raised in SBA's comments relate to all manufactures (not just small business manufacturers), further information on the costs of this technology as well as the benefits analysis, can be found in section VI of this preamble (and also chapters 6 and 9, respectively, of the Regulatory Impact Analysis).

Ambient Air Quality Standard. *See generally*, comment response 8.2.3 of the Summary and Analysis of Comments, and sections 12.6.2.2.9 and 12.6.2.2.10 of chapter 12 of the Draft RIA. These standards will also result in significant reductions of NMHC, which includes many carcinogenic air toxics. Indeed, given these facts, we are skeptical that an alternative of no aftertreatment-based PM standards for these engines would be appropriate under section 213(a)(4) of the Clean Air Act (*see* section VII.A above, where we found that "[w]e * * * do not see a basis in law or policy to adopt either of these options"). We believe that the transition and hardship provisions being finalized for small business engine manufacturers in today's action are reasonable and are a factor in our ultimate finding that the PM standards for engines in the 25–75 hp range are appropriate.

ii. Provisions for Small Business Equipment Manufacturers

The transition and hardship provisions that were proposed for small business nonroad equipment manufacturers are being finalized today, with some modifications.

Adopting an alternative on which we solicited comment, the final rule allows all equipment manufacturers the opportunity to choose between two options: (a) Manufacturers would be allowed to exempt 700 pieces of equipment over seven years, with one engine family; or (b) manufacturers using the small-volume allowance could exempt 525 machines over seven years (with a maximum of 150 in any given year) for each of the three power categories below 175 horsepower, and 350 machines over seven years (with a maximum of 100 in any given year) for the two power categories above 175 horsepower. Concurrent with the revised caps, manufacturers could exempt engines from more than one engine family under the small-volume allowance program. Based on sales information for small businesses, we estimated that the alternative small-volume allowance program to include lower caps and allow manufacturers to exempt more than one engine family would keep the total number of engines eligible for the allowance at roughly the same overall level as the 700-unit program. We believe that these provisions will afford small manufacturers the type of transition leeway recommended by the Panel. Further, these transition provisions could allow small business equipment manufacturers to postpone any redesign needed on low sales volume or difficult equipment packages, thus saving both money and strain on limited engineering staffs. Within limits, small business equipment manufacturers would be able to continue to use their current engine/equipment configuration and avoid out-of-cycle equipment redesign until the allowances are exhausted or the time limit passes.

We are not finalizing the requirement that small equipment manufacturers and importers have reported equipment sales using certified engines in model year 2002 or earlier. Please see section III.C.2.a.ii above for a detailed discussion on our decision to eliminate this requirement from today's rule.

We are also finalizing three additional provisions today. Two of these provisions are being finalized for all equipment manufacturers, and therefore small business equipment manufacturers may also take advantage of them. These are the Technical Hardship Provision and the Early Tier 4 Engine Incentive Program, and are discussed in greater detail in sections III.B.2.b and e above. The third provision is being finalized for small business equipment manufacturers only, for the 20–50 hp category. This provision is discussed in greater detail in section III.C.2.b.ii above.

iii. Provisions for Small Refiners

As previously discussed, we are finalizing standards for locomotive and marine diesel fuel today. Below are the regulatory transition and hardship provisions that we are finalizing to minimize the degree of hardship imposed upon small refiners by this program. With these provisions we are confident about going forward with the 500 ppm sulfur standard for NRLM diesel fuel in 2007, and the 15 ppm sulfur standard for nonroad diesel fuel in 2010 and locomotive and marine diesel fuel in 2012, for the rest of the industry. Given the small refiner relief provisions that are being finalized today, small refiners will be the only refiners permitted to continue selling 500 ppm fuel to nonroad, locomotive, and marine markets from 2010 until 2014 without the use of credits.

We are finalizing delayed compliance for small refiners today ("NRLM Delay" option). We are confident with going forward with these sulfur standards given the regulatory transition provisions being offered for small refiners. These delayed standards would allow for the continued production of higher sulfur NRLM fuel until June 1, 2010, and similarly, for the production of 500 ppm NRLM fuel until June 1, 2014.[255] This is identical to the relief proposed in the NPRM (which small refiners considered sufficient and supported) with the exception that it applies not only to nonroad fuel, but also to locomotive and marine fuel given the decision to finalize 15 ppm sulfur standards for locomotive and marine diesel fuel. Table X.C–2 below illustrates the delayed standards in relation to the general program. This delay option is not being finalized for the Northeast and mid-Atlantic areas due to the removal of the heating oil marker in these areas. However this is not expected to impact small refiners, and this will provide significant relief for small terminal operators. Further, this provision will be finalized in Alaska only if a refiner gets an approved compliance plan for segregating their fuel to the end user.

We also are finalizing transition provisions to encourage early compliance with the standards being finalized today. These provisions are:

- The NRLM credit option—Some small refiners have indicated that they might need to produce fuel meeting the NRLM diesel fuel sulfur standards earlier than required under the small refiner program described above (distribution systems might limit the number of grades of diesel fuel that will be carried, it may be economically advantageous to make compliant NRLM diesel fuel earlier to prevent losing market share, etc.) This option allows small refiners to participate in the NRLM diesel fuel sulfur credit banking and trading program discussed in section IV. Generating and selling credits could provide small refiners with funds to help defray the costs of early NRLM compliance.
- The NRLM/Gasoline Compliance Option—This option is available to small refiners that produce greater than 95 percent of their NRLM diesel fuel at the 15 ppm sulfur standard by June 1, 2006 and elect not to use the provision described above to earn NRLM diesel fuel sulfur credits for this early compliance.[256] For small refiners

[255] Since new engines with sulfur sensitive emission controls will begin to become widespread during this time, small refiner fuel will need to be segregated and only supplied for use in pre–2011 nonroad equipment or in locomotives or marine engines.

[256] This is down from the 100 percent requirement proposed to allow for some contamination losses in the process of delivering fuel from the refinery. As discussed earlier in this section, production volumes in the final rule are based upon actual delivered volumes. The 5 percent allowance for greater than 15 ppm fuel should provide adequate flexibility for any refiner's contamination issues, while not providing any

Continued

choosing this option the applicable small refiner annual average and per-gallon cap gasoline sulfur standards will be increased by 20 percent for the duration of the interim program; however, in no case may the per-gallon gasoline sulfur cap exceed 450 ppm.

A small refiner may choose to use the relaxed standards (the NRLM-Delay option), the NRLM Credit option, or both in combination. Thus any fuel that it produces from crude at or below the sulfur standards earlier than required will qualify for generating credits. However, the NRLM/Gasoline Compliance option may not be used in combination with either the NRLM Delay option or the NRLM Credit option, since a small refiner must produce at least 85 percent of its NRLM diesel fuel at the 15 ppm sulfur standard under the NRLM/Gasoline Compliance option.

Small refiners that choose to make use of the delayed nonroad diesel sulfur requirements would also delay to some extent the emission reductions that would otherwise have been achieved. However, the overall impact of these postponed emission reductions would be small in comparison to the overall program benefits, as small refiners represent only a fraction of national non-highway diesel production. Further, we are aware of some small refiners that plan to take advantage of one of the flexibility provisions that encourages early compliance with the standards. Absent specific provisions for small refiners, we would have to consider delaying the overall program until the burden of the program on many small refiners was diminished, which would delay the air quality benefits of the overall program. By providing temporary relief to small refiners, we are able to adopt a program that expeditiously reduces NRLM diesel fuel sulfur levels in a feasible manner for the industry as a whole.

TABLE X.C–2.—SULFUR STANDARDS FOR THE NONROAD DIESEL FUEL SMALL REFINER PROGRAM

(in parts per million (ppm)) [a]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015+
Non-Small—NR	....	500	500	500	15	15	15	15	15	15
Non-Small—LM	....	500	500	500	500	500	15	15	15	15
Small—all fuel	....	....	....	....	500	500	500	500	15	15

Notes: [a] New standards are assumed to take effect June 1 of the applicable year.

iv. Provisions for Small Distributors and Fuel Marketers

Though we did not propose any specific regulatory relief for small distributors and marketers of nonroad fuel, we are finalizing provisions to avoid the negative impact to small terminal operators raised in the public comments on our NPRM (that heating oil marker requirements would force small terminal operators to install expensive injection equipment and that they would not be able to recoup the costs). To mitigate the burden on these operators, terminals in much of PADD 1 will not have to add the fuel marker to home heating oil. No small refiner or credit fuel could be sold in this exclusion area. The exclusion area covers the vast majority of heating oil that will be marketed. Further, very little fuel above 500 ppm will be marketed outside of the exclusion area except directly from the refinery gate. Therefore, we expect that few terminals outside of the exclusion area would need to put in injection equipment.

6. Conclusion

A cost-to-sales ratio test, a ratio of the estimated annualized compliance costs to the value of sales per company, was performed for these entities during the proposal stage of the rulemaking. [257] From this cost-to-sales test, we found that approximately four percent (13 companies) of small entities in the engine and equipment manufacturing industry would be affected by between one and three percent of sales (*i.e.*, the estimated costs of compliance with the rule would be greater than one percent, but less than three percent, of their sales). One percent (four companies) of small entities would be affected by greater than three percent. In all, 17 of the 518 potentially affected small engine and equipment manufacturers are estimated to have compliance costs that could exceed one percent of their sales. (A complete discussion of the costs to engine and equipment manufacturers as a result of this final rule is located in Chapter 6 of the Final Regulatory Impact Analysis.)

Based on our outreach, fact-finding, and analysis of the potential impacts of our regulations on small businesses, it was determined that small refiners in general would likely experience a significant and disproportionate financial hardship in reaching the objectives of the nonroad diesel fuel sulfur program. One indication of this disproportionate hardship for small refiners is the relatively high cost per gallon projected for producing nonroad diesel fuel under the proposed program. Refinery modeling (of all refineries), indicates significantly higher refining costs for small refiners. Specifically, without special provisions, refining costs (for full compliance with the 15 ppm sulfur standards) for small refiners on average would be about 7 cents per gallon compared to about 5.7 cents per gallon for non-small refiners. (A complete discussion of the fuel-related costs as a result of this final rule is located in Chapter 7 of the Final Regulatory Impact Analysis.) However, we believe that the regulatory transition provisions that we are affording to small entities will significantly minimize this impact on these entities.

In addition, as contemplated by section 212 of SBREFA, EPA is also preparing a compliance guide to help small entities comply with this rule. This guide will be available within 60 days of the effective publication date of this rulemaking, and will be available on the Office of Transportation and Air Quality Web site. Small entities may also contact our office to obtain copies of the compliance guide.

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, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final

opportunity to significantly alter their compliance plans.

[257] The cost-to-sales ratio test assumes that control costs are completely absorbed by each entity and does not account for or consider interaction between manufacturers/producers and consumers in a market context.

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 one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation of why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

This rule contains no federal mandates for state, local, or tribal governments as defined by the provisions of Title II of the UMRA. The rule imposes no enforceable duties on any of these governmental entities. Nothing in the rule would significantly or uniquely affect small governments.

EPA has determined that this rule contains federal mandates that may result in expenditures of more than $100 million to the private sector in any single year. EPA believes that the final rule represents the least costly, most cost-effective approach to achieve the air quality goals of the rule. The costs and benefits associated with the final rule are discussed above and in the Regulatory Impact Analysis, as required by the UMRA.

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 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."

Under section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism 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 State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

Section 4 of the Executive Order contains additional requirements for rules that preempt State or local law, even if those rules do not have federalism implications (*i.e.*, the rules 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). Those requirements include providing all affected State and local officials notice and an opportunity for appropriate participation in the development of the regulation. If the preemption is not based on express or implied statutory authority, EPA also must consult, to the extent practicable, with appropriate State and local officials regarding the conflict between State law and Federally protected interests within the agency's area of regulatory responsibility.

This final 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 this rule, EPA did consult with representatives of various State and local governments in developing this rule. EPA has also consulted representatives from STAPPA/ALAPCO, which represents state and local air pollution officials.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the proposed rule from State and local officials, including from the State of Alaska.

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 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications."

This final rule does not have tribal implications as specified in Executive Order 13175. This rule will be implemented at the Federal level and impose compliance costs only on engine manufacturers and diesel fuel producers and distributors. Tribal governments will be affected only to the extent they purchase and use equipment with regulated engines. Thus, Executive Order 13175 does not apply to this rule.

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 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, "Actions Concerning Regulations That

Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)), requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, 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 proposed rulemaking, and notices of proposed 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." We have prepared a Statement of Energy Effects for this action as follows:

We have prepared a Statement of Energy Effects for this action as follows.

This rule's potential adverse effects on energy supply, distribution, or use have been analyzed, and are discussed in detail within the following documents:

1. Fuel provisions of the rule and flexibilities, including hardship provisions, are described in this Preamble, section IV.B. The provision of sufficient lead time for refiners is discussed in section IV.F.

2. Potential impacts on fuel supplies are summarized in Preamble section VI.A.5, RIA section VI.A.5, and within the Summary and Analysis of Comments document, section 4.6.3.

3. Costs of low-sulfur fuel are discussed in Preamble section VI.F, and RIA Chapter 7 (demand and production in 7.1, and refining costs in 7.2).

4. Price impacts are summarized in Preamble section VI.A, and RIA section 7.6, with distribution costs in section 7.4, alternative estimates of costs in 7.2, and effects of alternative demand projections in 7.2 as well. Uncertainty in fuel demand is also discussed in the Summary and Analysis of Comments section 2.3.2.2.

5. The need for adequate short-term investment in low sulfur refining capacity is addressed in RIA section 5.9.

6. The impacts of regulatory alternatives that were considered are discussed in Preamble section VII.

In summary, the cost of No. 2 distillate nonroad fuel is projected to increase overall by approximately 7 cents per gallon (in 2002 dollar terms) as a result of this rule. This would have a very small effect on production (projected reduction of approximately 0.02 %, or less than 4 million gallons per year by 2036).

The analysis also concludes that we do not expect this rule to have any adverse effect on the supply or distribution of NRLM fuel, nor to result in a significant increase in imports of NRLM fuel. Refiners will be unlikely to leave the NRLM fuel market and are unlikely to shut down due to this rule.

Price impacts will vary regionally in the U.S., and are difficult to project precisely. Analysis of various scenarios in RIA section 7.6 suggests that in PADDs 1 and 3 as well as 2, which account for the bulk of demand, prices could increase by almost 11 cents per gallon in the unlikely "maximum total cost" scenario of constrained capacity. In contrast, the "average total cost" scenario predicts a 5 cent per gallon increase in PADDs 1 and 3.

We do not believe there are any reasonable alternatives to the control of sulfur in nonroad fuel which would allow the reduction in NO_X and PM emissions from nonroad equipment required by today's rule. There are also no reasonable alternatives to the control of sulfur in locomotive and marine fuel which would provide the associated reductions in sulfur dioxide and sulfate PM emissions provided by the 500 and 15 ppm caps on the sulfur content of this fuel.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. 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.

This rule involves technical standards. The following paragraph describes how we specify testing procedures for engines subject to this proposal.

The International Organization for Standardization (ISO) has a voluntary consensus standard that can be used to test nonroad diesel engines. However, the current version of that standard (ISO 8178) is applicable only for steady-state testing, not for transient testing. As described in the Regulatory Impact Analysis, transient testing is an important part of the new emission-control program for these engines. We are therefore not adopting the ISO procedures in this rulemaking.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States before the rule is published in the **Federal Register**. This rule is a "major rule" as defined by 5 U.S.C. 804(2).

XI. Statutory Provisions and Legal Authority

Statutory authority for the engine controls adopted today can be found in sections 213 (which specifically authorizes controls on emissions from nonroad engines and vehicles), 203–209, 216 and 301 of the Clean Air Act, 42 U.S.C. 7547, 7522, 7523, 7424, 7525, 7541, 7542, 7543, 7550 and 7601.

Statutory authority for the new fuel controls is found in sections 211(c) and 211(i) of the Clean Air Act, which allow EPA to regulate fuels that either contribute to air pollution which endangers public health or welfare or which impair emission control equipment which is in general use or has been in general use. 42 U.S.C. 7545(c) and (i). Additional support for the procedural and enforcement-related aspects of the fuel controls in the final rule, including the record keeping requirements, comes from sections 114(a) and 301(a) of the CAA. 42 U.S.C. 7414(a) and 7601(a).

List of Subjects

40 CFR Part 9

Reporting and recordkeeping requirements.

40 CFR Part 69

Environmental protection, Air pollution controls.

40 CFR Part 80

Fuel additives, Gasoline, Imports, Incorporation by reference, Labeling, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

40 CFR Part 86

Environmental protection, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements.

40 CFR Part 89

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Labeling, Motor vehicle pollution, Reporting and recordkeeping requirements, Research, Vessels, Warranties.

40 CFR Part 94

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Penalties, Reporting and recordkeeping requirements, Vessels, Warranties.

40 CFR Parts 1039, 1048, and 1051

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 1065

Environmental protection, Administrative practice and procedure, Incorporation by reference, Reporting and recordkeeping requirements, Research.

40 CFR Part 1068

Environmental protection, Administrative practice and procedure, Confidential business information, Imports, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements, Warranties.

Dated: May 11, 2004.

Michael O. Leavitt,

Administrator.

■ For the reasons set out in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as set forth below.

PART 9—OMB APPROVALS UNDER THE PAPERWORK REDUCTION ACT

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

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

§ 9.1 [Amended]

■ 2. Section 9.1 is amended in the table by adding the center headings and the entries under those center headings in numerical order to read as follows:

* * * * *

Control of Emissions From New, Large Nonroad Spark-Ignition Engines

1048.20 2040–0460
1048.201–250 2040–0460
1048.345 2040–0460
1048.350 2040–0460
1048.420 2040–0460
1048.425 2040–0460

* * * * *

Control of Emissions from Recreational Engines and Vehicles

1051.201–255 2060–0104
1051.345 2060–0104
1051.350 2060–0104
1051.725 2060–0104
1051.730 2060–0104

* * * * *

General Compliance Provisions for Nonroad Programs

1068.5 2040–0460
1068.25 2040–0460
1068.27 2040–0460
1068.120 2040–0460
1068.201–260 2040–0460
1068.301–355 2040–0460
1068.450 2040–0460
1068.455 2040–0460
1068.501 2040–0460
1068.525 2040–0460
1068.530 2040–0460

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PART 69—SPECIAL EXEMPTIONS FROM THE REQUIREMENTS OF THE CLEAN AIR ACT

■ 3. The authority citation for part 69 continues to read as follows:

Authority: 42 U.S.C. 7545(c), (g), and (i), and 7625–1.

■ 4. Section 69.51 is revised to read as follows:

§ 69.51 Motor vehicle diesel fuel.

(a) Diesel fuel that is designated for use only in Alaska and is used only in Alaska, is exempt from the sulfur standard of 40 CFR 80.29(a)(1) and the dye provisions of 40 CFR 80.29(a)(3) and 40 CFR 80.29(b) until the implementation dates of 40 CFR 80.500, provided that:

(1) The fuel is segregated from nonexempt diesel fuel from the point of such designation; and

(2) On each occasion that any person transfers custody or title to the fuel, except when it is dispensed at a retail outlet or wholesale purchaser-consumer facility, the transferor must provide to the transferee a product transfer document stating:

This diesel fuel is for use only in Alaska. It is exempt from the federal low sulfur standards applicable to highway diesel fuel and red dye requirements applicable to non-highway diesel fuel only if it is used in Alaska.

(b) Beginning on the implementation dates under 40 CFR 80.500, motor vehicle diesel fuel that is designated for use in Alaska or is used in Alaska, is subject to the applicable provisions of 40 CFR part 80, subpart I, except as provided under 40 CFR 69.52(c), (d), and (e) for commingled motor vehicle and non-motor vehicle diesel fuel.

(c) The Governor of Alaska may submit for EPA approval, by April 1, 2002, a plan for implementing the motor vehicle diesel fuel sulfur standard in Alaska as an alternative to the temporary compliance option provided under 40 CFR 80.530 through 80.532. If EPA approves an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel fuel subject to paragraph (b) of this section.

■ 5. A new § 69.52 is added to read as follows:

§ 69.52 Non-motor vehicle diesel fuel.

(a) *Definitions.* (1) *Areas accessible by the Federal Aid Highway System* are the geographical areas of Alaska designated by the State of Alaska as being accessible by the Federal Aid Highway System.

(2) *Areas not accessible by the Federal Aid Highway System* are all other geographical areas of Alaska.

(3) *Nonroad, locomotive, or marine diesel fuel (NRLM)* has the meaning given in 40 CFR 80.2.

(b) *Applicability.* NRLM diesel fuel and heating oil that are used or intended for use in areas of Alaska accessible by the Federal Aid Highway System are subject to the provisions of 40 CFR part 80, subpart I, except as provided in paragraphs (c), (d) and (e) of this section.

(c) *Dye and marker.* (1) NRLM diesel fuel and heating oil referred to in paragraph (b) of this section are exempt from the red dye requirements, and the presumptions associated with the red dye requirements, under 40 CFR 80.520(b)(2) and 80.510(d)(5), (e)(5), and (f)(5).

(2) NRLM diesel fuel and heating oil referred to in paragraph (b) of this section are exempt from the marker solvent yellow 124 requirements, and

the presumptions associated with the marker solvent yellow 124 requirements, under 40 CFR 80.510(d) through (f).

(3) Exempt NRLM diesel fuel and heating oil must be segregated from all non-exempt NRLM diesel fuel and heating oil.

(4) Exempt heating oil must be segregated from exempt NRLM diesel fuel unless it also meets the standards of 40 CFR 80.510 applicable to the NRLM diesel fuel.

(5) Exempt NRLM diesel fuel and heating oil must be segregated from motor vehicle diesel fuel, unless it also meets the standards of 40 CFR 80.520 applicable to the motor vehicle diesel fuel.

(d) *Product transfer documents.* Product Transfer Documents for exempt NRLM diesel fuel and heating oil shall include the language specified in 40 CFR 80.590(a) applicable to undyed diesel fuel for the appropriate sulfur level, and the following additional language as applicable:

(1) For exempt NRLM diesel fuel and heating oil, including commingled fuel under paragraph (c)(4) or (c)(5) of this section: "Exempt from red dye requirement applicable to diesel fuel for non-highway purposes if it is used only in Alaska."

(2) For exempt heating oil, including commingled fuel under paragraph (c)(4) or (c)(5) of this section: "Exempt from marker solvent yellow 124 requirement applicable to heating oil if it is used only in Alaska."

(3) For exempt 500 ppm sulfur LM diesel fuel, including commingled fuel under paragraph (c)(4) or (c)(5) of this section: "Exempt from marker solvent yellow 124 requirement applicable to 500 ppm sulfur LM diesel fuel if it is used only in Alaska."

(e) *Pump labels.* (1) Pump labels for exempt NRLM diesel fuel and heating oil shall contain the language specified in 40 CFR 80.570 through 80.574 for the applicable fuel type and time frame, unless the fuel is commingled under paragraph (c)(4) or (c)(5) of this section.

(2) Pump labels for exempt NRLM diesel fuel and heating oil that are commingled shall contain the language specified in 40 CFR 80.570 through 80.574 for NRLM diesel fuel and the applicable time frame.

(3) Pump labels for exempt NRLM diesel fuel and heating oil that are commingled with motor vehicle diesel fuel shall contain the following language for the applicable sulfur level and time frame:

(i) *500 ppm sulfur diesel fuel.* From June 1, 2006 through September 30, 2010.

LOW SULFUR DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal Law prohibits use in model year 2007 and later highway diesel vehicles and engines

Its use may damage these vehicles and engines.

For use in all other diesel vehicles and engines.

(ii) *15 ppm sulfur diesel fuel.* From June 1, 2006 through May 31, 2010.

ULTRA-LOW SULFUR DIESEL FUEL (15 ppm Sulfur Maximum)

Required for model year 2007 and later highway diesel vehicles and engines.

Recommended for use in all diesel vehicles and engines.

(iii) *15 ppm sulfur diesel fuel.* From June 1, 2010, and beyond,

ULTRA-LOW SULFUR DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all highway and nonroad diesel engines

Recommended for use in all diesel vehicles and engines.

(f) Non-motor vehicle diesel fuel and heating oil that is used or intended for use only in areas of Alaska not accessible by the Federal Aid Highway System, are excluded from the applicable provisions of 40 CFR part 80, subpart I, except that—

(1) All model year 2011 and later nonroad diesel engines and equipment must be fueled only with diesel fuel that meets the specifications of 40 CFR 80.510(b) or (c);

(2) The following language shall be added to any product transfer document: "This fuel is for use only in those areas of Alaska not accessible by the FAHS"; and

(3) Pump labels for such fuel that does not meet the specifications of 40 CFR 80.510(b) or (c) shall contain the following language:

HIGH SULFUR DIESEL FUEL (may be greater than 15 Sulfur ppm)

WARNING

Federal Law *prohibits* use in model year 2007 and later highway diesel vehicles and engines, or in model year 2011 and later nonroad diesel engines and equipment.

Its use may damage these vehicles and engines.

(g) Alternative labels to those specified in paragraphs (e)(3) and (f)(3) of this section may be used as approved by the Administrator.

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

■ 6. The authority citation for part 80 continues to read as follows:

Authority: 42 U.S.C. 7414, 7545, and 7601(a).

■ 7. Section 80.2 is amended by adding paragraph (f) and revising paragraphs (j), (o), (x), (y), and (xx), removing and reserving paragraph (nn), adding and reserving paragraphs (yy), and (zz), and adding and reserving paragraphs (aaa) through (rrr) to read as follows:

§ 80.2 Definitions.

* * * * *

(f) *Previously designated diesel fuel* or *PDD* means diesel fuel that has been previously designated and included by a refiner or importer in a batch for purposes of complying with the standards and requirements of subpart I of this part.

* * * * *

(j) *Retail outlet* means any establishment at which gasoline, diesel fuel, methanol, natural gas or liquified petroleum gas is sold or offered for sale for use in motor vehicles or nonroad engines, including locomotive engines or marine engines.

* * * * *

(o) *Wholesale purchaser-consumer* means any person that is an ultimate consumer of gasoline, diesel fuel, methanol, natural gas, or liquified petroleum gas and which purchases or obtains gasoline, diesel fuel, natural gas or liquified petroleum gas from a supplier for use in motor vehicles or nonroad engines, including locomotive engines or marine engines and, in the case of gasoline, diesel fuel, methanol or liquified petroleum gas, receives delivery of that product into a storage tank of at least 550-gallon capacity substantially under the control of that person.

* * * * *

(x) *Diesel fuel* means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (*e.g.*, biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

(y) *Motor vehicle diesel fuel* means any diesel fuel or other distillate fuel that is used, intended for use, or made available for use in motor vehicles or motor vehicle engines.

* * * * *

(xx) *Diesel fuel additive* means any substance not composed solely of carbon and/or hydrogen, or of diesel blendstocks, that is added to, intended to be added to, used in, or offered for use in motor vehicle diesel fuel or NRLM diesel fuel or in diesel motor vehicle or diesel NRLM engine fuel systems subsequent to the production of diesel fuel by processing crude oil from refinery processing units.

(yy)–(zz) [Reserved]

(aaa) *Distillate fuel* means diesel fuel and other petroleum fuels that can be used in engines that are designed for diesel fuel. For example, jet fuel, heating oil, kerosene, No. 4 fuel, DMX, DMA, DMB, and DMC are distillate fuels; and natural gas, LPG, gasoline, and residual fuel are not distillate fuels. Blends containing residual fuel may be distillate fuels.

(bbb) *Residual fuel* means a petroleum fuel that can only be used in diesel engines if it is preheated before injection. For example, No. 5 fuels, No. 6 fuels, and RM grade marine fuels are residual fuels. Note: Residual fuels do not necessarily require heating for storage or pumping.

(ccc) *Heating oil* means any No. 1 or No. 2 distillate fuel that is sold for use in furnaces, boilers, stationary diesel engines, and similar applications and which is commonly or commercially known or sold as heating oil, fuel oil, and similar trade names, and that is not jet fuel, kerosene, or MVNRLM diesel fuel.

(ddd) *Jet fuel* means any distillate fuel used, intended for use, or made available for use in aircraft.

(eee) *Kerosene* means any No.1 distillate fuel commonly or commercially sold as kerosene.

(fff) *#1D* means the distillate fuel classification relating to "No. 1–D" diesel fuels as described in ASTM D 975–04. The Director of the Federal Register approved the incorporation by reference of ASTM D 975–04, Standard Specification for Diesel Fuel Oils, as prescribed in 5 U.S.C. 552(a) and 1 CFR part 51. Anyone may purchase copies of this standard from the American Society for Testing and Materials, 100 Barr Harbor Dr., West Conshohocken, PA 19428. Anyone may inspect copies at the U.S. EPA, Air and Radiation Docket and Information Center, 1301 Constitution Ave., NW., Room B102, EPA West Building, Washington, DC 20460 or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(ggg) *#2D* means the distillate fuel classification relating to "No. 2–D" diesel fuels as described in ASTM D 975–04.

(hhh)–(jjj) [Reserved]

(kkk) *Nonroad diesel engine* means an engine that is designed to operate with diesel fuel that meets the definition of nonroad engine in 40 CFR 1068.30, including locomotive and marine diesel engines.

(lll) *Locomotive engine* means an engine used in a locomotive as defined under 40 CFR 92.2.

(mmm) *Marine engine* and *Category 3* have the meanings given under 40 CFR 94.2.

(nnn) *Nonroad, locomotive, or marine (NRLM) diesel fuel* means any diesel fuel or other distillate fuel that is used, intended for use, or made available for use, as a fuel in any nonroad diesel engines, including locomotive and marine diesel engines, except the following: Distillate fuel with a T90 greater than 700 °F that is used only in Category 2 and 3 marine engines is not NRLM diesel fuel. Use the distillation test method specified in 40 CFR 1065.1010 to determine the T90 of the fuel. NR diesel fuel and LM diesel fuel are subcategories of NRLM diesel fuel.

(ooo) *Nonroad (NR) diesel fuel* means any NRLM diesel fuel that is not "locomotive or marine (LM) diesel fuel."

(ppp) *Locomotive or marine (LM) diesel fuel* means any diesel fuel or other distillate fuel that is used, intended for use, or made available for use, as a fuel in locomotive or marine diesel engines, except for the following fuels:

(1) Fuel that is also used, intended for use, or made available for use in motor vehicle engines or nonroad engines other than locomotive and marine diesel engines is not LM diesel fuel.

(2) Distillate fuel with a T90 greater than 700 °F that is used only in Category 2 and 3 marine engines is not LM diesel fuel. Use the distillation test method specified in 40 CFR 1065.1010 to determine the T90 of the fuel.

(qqq) *MVNRLM diesel fuel* means any diesel fuel or other distillate fuel that meets the definition of motor vehicle (MV) or nonroad, locomotive, or marine (NRLM) diesel fuel. Motor vehicle diesel fuel, NRLM diesel fuel, NR diesel fuel, and LM diesel fuel are subcategories of MVNRLM diesel fuel.

(rrr) *Solvent yellow 124* means N-ethyl-N-[2-[1-(2-methylpropoxy)ethoxyl]-4-phenylazo]-benzeneamine.

■ 8. Section 80.230 is amended by revising paragraph (b) to read as follows:

§ 80.230 Who is not eligible for the hardship provisions for small refiners?

* * * * *

(b)(1)(i) Refiners who qualify as small under § 80.225 and subsequently cease production of diesel fuel from processing crude oil through refinery processing units, or employ more than 1,500 people or exceed the 155,000 bpcd crude oil capacity limit after January 1, 2004 as a result of merger with or acquisition of or by another entity, are disqualified as small refiners, except this shall not apply in the case of a merger between two previously approved small refiners. If disqualification occurs, the refiner shall notify EPA in writing no later than 20 days following this disqualifying event.

(ii) Except as provided under paragraph (b)(1)(iii) of this section, any refiner whose status changes under this paragraph shall meet the applicable standards of § 80.195 within a period of up to 30 months of the disqualifying event for any of its refineries that were previously subject to the small refiner standards of § 80.240(a). However, such period shall not extend beyond December 31, 2007, or, for refineries for which the Administrator has approved an extension of the small refiner gasoline sulfur standards under § 80.553(c), December 31, 2010.

(iii) A refiner may apply to EPA for an additional six months to comply with the standards of § 80.195 if more than 30 months will be required for the necessary engineering, permitting, construction, and start-up work to be completed. Such applications must include detailed technical information supporting the need for additional time. EPA will base its decision to approve additional time on the information provided by the refiner and on other relevant information. In no case will EPA extend the compliance date beyond December 31, 2007, or, for refineries for which the Administrator has approved an extension of the small refiner gasoline sulfur standards under § 80.553(c), December 31, 2010.

(iv) During the period of time up to 30 months provided under paragraph (b)(1)(ii) of this section, and any extension provided under paragraph (b)(1)(iii) of this section, the refiner may not generate gasoline sulfur credits under § 80.310.

(2) Any refiner who qualifies as a small refiner under § 80.225 may elect to meet the standards under § 80.195 by notifying EPA in writing no later than November 15 prior to the year that the change will occur. Any refiner whose status changes under this paragraph (b)(2) shall meet the standards under § 80.195 beginning with the first averaging period subsequent to the status change.

■ 9. Section 80.240 is amended by adding paragraph (f) to read as follows:

§ 80.240 What are the small refiner gasoline sulfur standards?

* * * * *

(f)(1) In the case of a refiner without approved small refiner status who acquires a refinery from a refiner with approved small refiner status under § 80.235, the applicable small refiner standards under paragraph (a) of this section will apply to the acquired small refinery for a period up to 30 months from the date of acquisition of the refinery, but no later than December 31, 2007, or, for a refinery for which the Administrator has approved an extension of the small refiner gasoline sulfur standards under § 80.553(c), December 31, 2010, after which time the standards of § 80.195 shall apply to the acquired refinery.

(2) A refiner may apply to EPA for an additional six months to comply with the standards of § 80.195 for the acquired refinery if more than 30 months will be required for the necessary engineering, permitting, construction, and start-up work to be completed. Such applications must include detailed technical information supporting the need for additional time. EPA will base its decision to approve additional time on information provided by the refiner and on other relevant information. In no case will EPA extend the compliance date beyond December 31, 2007, or, for a refinery for which the Administrator has approved an extension of the small refiner gasoline sulfur standards under § 80.553(c), December 31, 2010.

■ 10. Section 80.500 is amended by removing paragraph (f) and revising the section heading to read as follows:

80.500 What are the implementation dates for the motor vehicle diesel fuel sulfur control program?

■ 11. Section 80.501 is revised to read as follows:

§ 80.501 What fuel is subject to the provisions of this subpart?

(a) *Included fuel and additives*. The provisions of this subpart apply to the following fuels and additives except as specified in paragraph (b) of this section:

(1) Motor vehicle diesel fuel.

(2) Nonroad, locomotive, or marine diesel fuel.

(3) Diesel fuel additives.

(4) Heating oil.

(5) Other distillate fuels.

(6) Motor oil that is used as or intended for use as fuel in diesel motor vehicles or nonroad diesel engines or is blended with diesel fuel for use in diesel motor vehicles or nonroad diesel engines, including locomotive and marine diesel engines, at any downstream location.

(b) *Excluded fuel*. The provisions of this subpart do not apply to distillate fuel that is designated for export outside the United States in accordance with § 80.598, identified for export by a transfer document as required under § 80.590, and that is exported.

■ 12. A new § 80.502 is added to read as follows:

§ 80.502 What definitions apply for purposes of this subpart?

The definitions of § 80.2 and the following additional definitions apply to this subpart I:

(a) *Entity* means any refiner, importer, distributor, retailer or wholesale-purchaser consumer of any distillate fuel.

(b) *Facility* means any place, or series of places, where an entity produces, imports, or maintains custody of any distillate fuel from the time it is received to the time custody is transferred to another entity, except as described in paragraphs (b)(1) through (b)(4) of this section:

(1) Where an entity maintains custody of a batch of diesel fuel from one place in the distribution system to another place (*e.g.*, from a pipeline to a terminal), all owned by the same entity, both places combined are considered to be one single aggregated facility, except where an entity chooses to treat components of such an aggregated facility as separate facilities. The choice made to treat these places as separate facilities may not be changed by the entity during any applicable compliance period. Except as specified in paragraph (b)(2) of this section, where compliance requirements depend upon facility-type, the entire facility must comply with the requirements that apply to its components as follows:

(i) If an aggregated facility includes a refinery, the entire facility must comply with the requirements applicable to refineries.

(ii) If an aggregated facility includes a truck loading terminal but not a refinery, the entire facility must comply with the requirements applicable to truck loading terminals.

(2) A refinery or import facility may not be aggregated with facilities that receive fuel from other refineries or import facilities, either directly or indirectly. For example, a refinery may not be aggregated with a terminal that receives any fuel from a common carrier pipeline. However, a refinery may be aggregated with a pipeline and terminal that are owned by the same entity and which receive no fuel from any source other than the refinery. If a refinery or import facility is aggregated with other facilities, then the aggregated facility is treated as a refinery or import facility.

(3) Retail outlets or wholesale purchaser consumers may not be aggregated with any other facility.

(4) Where an entity maintains custody of diesel fuel in one or more mobile components (*e.g.*, rail, barge, or trucking operations) the mobile components may be aggregated as a single facility. Mobile components may also be aggregated with a facility from which they receive fuel or a facility to which they deliver fuel. However, mobile components may not be aggregated with both a facility from which they receive fuel and a facility to which they deliver fuel.

(5) An individual refinery or contiguous pipeline may not be subdivided into more than one facility. An individual terminal may not be subdivided into more than one facility unless approved by the Administrator.

(c) *Truck loading terminal* means any facility that dyes NRLM diesel fuel, pays taxes on motor vehicle diesel fuel per IRS code (26 CFR part 48), or adds a fuel marker pursuant to § 80.510 to heating oil and delivers diesel fuel or heating oil into trucks for delivery to retail or ultimate consumer locations.

(d) *Batch* means a quantity of diesel fuel or distillate which is homogeneous with regard to those properties that are specified for MVNRLM diesel fuel under this subpart I of this part, has the same designation under this subpart I (if applicable), and whose custody is transferred from one facility to another facility.

(e) *Downstream location* means any point in the diesel fuel distribution system that is downstream of refineries and import facilities, for example, diesel fuel at facilities of distributors, carriers, retailers, kerosene blenders, and wholesale purchaser-consumers.

■ 13. A new § 80.510 is added to read as follows:

§ 80.510 What are the standards and marker requirements for NRLM diesel fuel?

(a) *Beginning June 1, 2007*. Except as otherwise specifically provided in this subpart, all NRLM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content. 500 parts per million (ppm) maximum.

(2) Cetane index or aromatic content, as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

(b) *Beginning June 1, 2010*. Except as otherwise specifically provided in this subpart, all NR and LM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content.

(i) 15 ppm maximum for NR diesel fuel.

(ii) 500 ppm maximum for LM diesel fuel.

(2) Cetane index or aromatic content, as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

(c) *Beginning June 1, 2012.* Except as otherwise specifically provided in this subpart, all NRLM diesel fuel is subject to the following per-gallon standards:

(1) Sulfur content. 15 ppm maximum.

(2) Cetane index or aromatic content, as follows:

(i) A minimum cetane index of 40; or

(ii) A maximum aromatic content of 35 volume percent.

(d) *Marking provisions.* From June 1, 2007 through May 31, 2010:

(1) Except as provided for in paragraph (i) of this section, prior to distribution from a truck loading terminal, all heating oil shall contain six milligrams per liter of marker solvent yellow 124.

(2) All motor vehicle and NRLM diesel fuel shall be free of solvent yellow 124.

(3) Any diesel fuel that contains greater than or equal to 0.10 milligrams per liter of marker solvent yellow 124 shall be deemed to be heating oil and shall be prohibited from use in any motor vehicle or nonroad diesel engine (including locomotive, or marine diesel engines).

(4) Except as provided for in paragraph (i) of this section, any diesel fuel, other than jet fuel or kerosene that is downstream of a truck loading terminal, that contains less than 0.10 milligrams per liter of marker solvent yellow 124 shall be considered motor vehicle diesel fuel or NRLM diesel fuel, as appropriate.

(5) Any heating oil that is required to contain marker solvent yellow 124 pursuant to the requirements of this paragraph (d) must also contain visible evidence of dye solvent red 164.

(e) *Marking provisions.* From June 1, 2010 through May 31, 2012:

(1) Except as provided for in paragraph (i) of this section, prior to distribution from a truck loading terminal, all heating oil and diesel fuel designated as 500 ppm sulfur LM diesel fuel shall contain six milligrams per liter of solvent yellow 124.

(2) All motor vehicle and NR diesel fuel shall be free of marker solvent yellow 124.

(3) Any diesel fuel that contains greater than or equal to 0.10 milligrams per liter of marker solvent yellow 124 shall be deemed to be LM diesel fuel or heating oil, as appropriate, and shall be prohibited from use in any motor vehicle or nonroad diesel engine (except for locomotive or marine diesel engines).

(4) Except as provided for in paragraph (i) of this section, any diesel fuel, other than jet fuel or kerosene that is downstream of a truck loading terminal, that contains less than 0.10 milligrams per liter of marker solvent yellow 124 shall be considered motor vehicle diesel fuel or NR diesel fuel, as appropriate.

(5) Any LM diesel fuel or heating oil that is required to contain marker solvent yellow 124 pursuant to the requirements of this paragraph (e) must also contain visible evidence of dye solvent red 164.

(f) *Marking provisions.* Beginning June 1, 2012:

(1) Except as provided for in paragraph (i) of this section, prior to distribution from a truck loading terminal, all heating oil shall contain six milligrams per liter of marker solvent yellow 124.

(2) All motor vehicle and NRLM diesel fuel shall be free of marker solvent yellow 124.

(3) Any diesel fuel that contains greater than or equal to 0.10 milligrams per liter of marker solvent yellow 124 shall be deemed to be heating oil and shall be prohibited from use in any motor vehicle or nonroad diesel engine (including locomotive, or marine diesel engines).

(4) Except as provided for in paragraph (i) of this section, any diesel fuel, other than jet fuel or kerosene that is downstream of a truck loading terminal, that contains less than 0.10 milligrams per liter of marker solvent yellow 124 shall be considered motor vehicle diesel fuel or NRLM diesel fuel, as appropriate.

(5) Any heating oil that is required to contain marker solvent yellow 124 pursuant to the requirements of this paragraph (f) must also contain visible evidence of dye solvent red 164.

(g) Special provisions in this part apply to the following areas:

(1) Northeast/Mid-Atlantic Area which includes the following states and counties: North Carolina, Virginia, Maryland, Delaware, New Jersey, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, Maine, Washington D.C., New York (except for the counties of Chautauqua, Cattaraugus, and Allegany), Pennsylvania (except for the counties of Erie, Warren, Mc Kean, Potter, Cameron, Elk, Jefferson, Clarion, Forest, Venango, Mercer, Crawford, Lawrence, Beaver, Washington, and Greene), and the eight eastern-most counties of West Virginia (Jefferson, Berkeley, Morgan, Hampshire, Mineral, Hardy, Grant, and Pendleton).

(2) Alaska.

(h) Pursuant and subject to the provisions of §§ 80.536, 80.554, 80.560, and 80.561:

(1) Except as provided in paragraph (j) of this section, from June 1, 2007 through May 31, 2010, NRLM diesel fuel produced or imported in full compliance with the requirements of §§ 80.536, 80.554, 80.560, and 80.561 is exempt from the per-gallon sulfur content standard and cetane or aromatics standard of paragraph (a) of this section.

(2) Except as provided in paragraph (j) of this section, from June 1, 2010 through May 31, 2012 for NR diesel fuel and from June 1, 2012 through May 31, 2014 for NRLM diesel fuel produced or imported in full compliance with the requirements of §§ 80.536, 80.554, 80.560, and 80.561 is exempt from the per-gallon standards of paragraphs (b) and (c) of this section, but is subject to the per-gallon standards of paragraph (a) of this section.

(i) The marking requirements of paragraphs (d)(1), (d)(4), (e)(1), (e)(4), (f)(1), and (f)(4) of this section do not apply to heating oil, or, for paragraphs (e)(1) and (e)(4) of this section, diesel fuel designated as LM diesel fuel that is distributed from a truck loading terminal located within the areas listed in paragraphs (g)(1) and (g)(2) of this section and is for sale or intended for sale within these areas, or that is distributed from any other truck loading terminal and is for sale or intended for sale within the area listed in (g)(2) of this section.

(j) The provisions of paragraphs (h)(1) and (h)(2) of this section do not apply to diesel fuel sold or intended for sale in the areas listed in paragraph (g)(1) of this section that is produced or imported in full compliance with the requirements of §§ 80.536 and 80.554 or to diesel fuel sold or intended for sale in the area listed in paragraph (g)(2) of this section that is produced or imported in full compliance with the requirements of § 80.536.

■ 14. A new § 80.511 is added to read as follows:

§ 80.511 What are the per-gallon and marker requirements that apply to NRLM diesel fuel and heating oil downstream of the refiner or importer?

(a) *Applicable dates for marker requirements.* Beginning June 1, 2006, all NRLM diesel fuel shall contain less than 0.10 milligrams per liter of the marker solvent yellow 124, except for

LM diesel fuel subject to the marking requirements of § 80.510(e).

(b) *Applicable dates for per-gallon standards.* (1) Beginning June 1, 2006, all NRLM diesel fuel must comply with the per-gallon sulfur standard for the designation or classification stated on its PTD, pump label, or other documentation. Based on the provisions of § 80.510(h) and (j), there is no uniform downstream sulfur standard until the downstream dates identified in paragraphs (b)(3) through (b)(8) of this section.

(2) Except as provided in paragraphs (b)(5) and (b)(8) of this section, beginning December 1, 2010, all NRLM diesel fuel must comply with the cetane index or aromatics standard of § 80.510.

(3) Except as provided in paragraphs (b)(5) through (b)(8) of this section, the per-gallon sulfur standard of § 80.510(a) shall apply to all NRLM diesel fuel beginning August 1, 2010 for all downstream locations other than retail outlets or wholesale purchaser-consumer facilities, shall apply to all NRLM diesel fuel beginning October 1, 2010 for retail outlets and wholesale purchaser-consumer facilities, and shall apply to all NRLM diesel fuel beginning December 1, 2010 for all locations.

(4) Except as provided in paragraphs (b)(5) through (b)(8) of this section, the per-gallon sulfur standard of § 80.510(c) shall apply to all NRLM diesel fuel beginning August 1, 2014 for all downstream locations other than retail outlets or wholesale purchaser-consumer facilities, shall apply to all NRLM diesel fuel beginning October 1, 2014 for retail outlets and wholesale purchaser-consumer facilities, and shall apply to all NRLM diesel fuel beginning December 1, 2014 for all locations. This paragraph (b)(4) does not apply to LM diesel fuel that is sold or intended for sale in areas other than those listed in § 80.510(g)(1) or (g)(2).

(5) For all NRLM diesel fuel that is sold or intended for sale in the areas listed in § 80.510(g)(1), the per-gallon sulfur standard and the cetane index or aromatics standard of 80.510(a) shall apply to all NRLM diesel fuel beginning August 1, 2007 for all downstream locations other than retail outlets or wholesale purchaser-consumer facilities, shall apply to all NRLM diesel fuel beginning October 1, 2007 for retail outlets and wholesale purchaser-consumer facilities, and shall apply to all NRLM diesel fuel beginning December 1, 2007 for all locations.

(6) For all NR diesel fuel that is sold or intended for sale in the areas listed in § 80.510(g)(1), the per-gallon sulfur standard of § 80.510(b) shall apply to all NR diesel fuel beginning August 1, 2010 for all downstream locations other than retail outlets or wholesale purchaser-consumer facilities, shall apply to all NR diesel fuel beginning October 1, 2010 for retail outlets and wholesale purchaser-consumer facilities, and shall apply to all NR diesel fuel beginning December 1, 2010 for all locations.

(7) For all NRLM diesel fuel that is sold or intended for sale in the areas listed in § 80.510(g)(1), the per-gallon sulfur standard of § 80.510(c) shall apply to all NRLM diesel fuel beginning August 1, 2012 for all downstream locations other than retail outlets or wholesale purchaser-consumer facilities, shall apply to all NRLM diesel fuel beginning October 1, 2012 for retail outlets and wholesale purchaser-consumer facilities, and shall apply to all NRLM diesel fuel beginning December 1, 2012 for all locations.

(8) The provisions of paragraphs (b)(5) through (b)(7) of this section shall apply for all NRLM or NR diesel fuel that is sold or intended for sale in the area listed in § 80.510(g)(2), except for NRLM or NR diesel fuel that is produced in accordance with a compliance plan approved under § 80.554.

(9) For the purposes of this section, distributors that have their own fuel storage tanks and deliver only to ultimate consumers shall be treated the same as retailers and their facilities treated the same as retail outlets.

■ 15. A new § 80.512 is added to read as follows:

§ 80.512 May an importer treat diesel fuel as blendstock?

An importer may exclude diesel fuel that it imports from the requirements under this subpart, and instead may designate such diesel fuel as diesel fuel treated as blendstock (DTAB), if all the following conditions are met:

(a) The DTAB must be included in all applicable designation, credit and compliance calculations for diesel fuel for a refinery operated by the same entity that is the importer . That entity must meet all refiner standards and requirements.

(b) The importer entity may not transfer title of the DTAB to another entity until the DTAB has been used to produce diesel fuel and all refiner standards and requirements have been met for the diesel fuel produced.

(c) The refinery at which the DTAB is used to produce diesel fuel must be physically located at either the same terminal at which the DTAB first arrives in the U.S., the import facility, or at a facility to which the DTAB is directly transported from the import facility.

(d) The DTAB must be completely segregated from any other diesel fuel, including any diesel fuel tank bottoms, prior to the point of blending, sampling and testing in the importer entity's refinery operation. The DTAB may, however, be added to a diesel fuel blending tank where the diesel fuel tank bottom is not included as part of the batch volume for a prior batch. In addition, the DTAB may be placed into a storage tank that contains other DTAB imported by that importer. The DTAB also may be discharged into a tank containing finished diesel fuel of the same category as the diesel fuel which will be produced using the DTAB (for example, 15 ppm sulfur undyed or 15 ppm sulfur dyed diesel fuel) provided the blending process is performed in that same tank.

(e) The entity must account for the volume of diesel fuel produced using DTAB in a manner that excludes the volume of any previously designated diesel fuel. The diesel fuel tank bottom may not be included in the company's refinery compliance calculations for that batch of diesel fuel if the fuel in that tank bottom has been previously designated by a refiner or importer. This exclusion of previously designated diesel fuel must be accomplished using the following approach:

(1) Determine the volume of any tank bottom that is previously designated diesel fuel before any diesel fuel production begins.

(2) Add the DTAB plus any blendstock to the storage tank, and completely mix the tank.

(3) Determine the volume and sulfur content of the diesel fuel contained in the storage tank after blending is complete. Mathematically subtract the volume of the tank bottom to determine the volume of the DTAB plus blendstock added, and subsequently transferred to another facility. Such fuel is reported to EPA as a batch of diesel fuel under §§ 80.593, 80.601, and 80.604.

(4) If previously designated motor vehicle diesel fuel having a sulfur content of 15 ppm or less is blended with DTAB, and the combined product after blending has a sulfur content that exceeds 15 ppm, the importer entity, in its capacity as a refiner, must redesignate all the diesel fuel as 500 ppm sulfur motor vehicle diesel fuel for purposes of the temporary compliance option under § 80.530, or other permissible redesignation under § 80.598. If #2D 15 ppm sulfur motor vehicle diesel fuel is redesignated as #2D 500 ppm sulfur motor vehicle diesel fuel, such entity must apply the volume of previously designated 15 ppm sulfur diesel fuel, for purposes of its operations as a distributor, to its

downgrading limitation under § 80.527, if applicable, and for volume balancing purposes under § 80.599.

(5) As an alternative to paragraphs (e)(1) through (e)(4) of this section, where an importer has a blending tank that is used only to combine DTAB and blending components, and no previously designated diesel fuel is added to the tank, the importer entity, in its capacity as a refiner, may account for the diesel fuel produced in such a blending tank by sampling and testing for the sulfur content of the batch after DTAB and blendstock are added and mixed, and reporting the volume of diesel fuel transferred from that tank to a different facility, up to the point where a new blend is produced by adding new DTAB and blendstock.

(f) The importer must include the volume and sulfur content of each batch of DTAB in the annual importer reports to EPA, as prescribed under §§ 80.593, 80.601, and 80.604, but with a notation that the batch is not included in the importer compliance calculations because the product is DTAB. Any DTAB that ultimately is not used in the importer's refinery operation (for example, a tank bottom of DTAB at the conclusion of the refinery operation), must be treated as newly imported diesel fuel, for which all required sampling and testing, and recordkeeping must be accomplished, and included in the importer's compliance calculations for the averaging period when this sampling and testing occurs.

(g) The importer must retain records that reflect the importation, sampling and testing, and physical movement of any DTAB, and must make these records available to EPA on request.

■ 16. A new § 80.513 is added to read as follows:

§ 80.513 What provisions apply to transmix processing facilities?

For purposes of this section, transmix means a mixture of finished fuels that no longer meets the specifications for a fuel that can be used or sold without further processing. This section applies to refineries that produce diesel fuel from transmix by distillation or other refining processes but do not produce diesel fuel by processing crude oil. This section only applies to the volume of diesel fuel produced by such a transmix processor using these processes, and does not apply to any diesel fuel produced by the blending of blendstocks.

(a) From June 1, 2006 through May 31, 2010, motor vehicle diesel fuel produced by a transmix processor is subject to the 500 ppm sulfur standard under § 80.520(c).

(b) Beginning June 1, 2010, motor vehicle diesel fuel produced by a transmix processor is subject to the sulfur standard under § 80.520(a)(1).

(c) From June 1, 2007 through May 31, 2010, NRLM diesel fuel produced by a transmix processor is exempt from the standards of § 80.510(a). This paragraph (c) does not apply to NRLM diesel fuel that is sold or intended for sale in the areas listed in § 80.510(g)(1) or (g)(2).

(d) From June 1, 2010 through May 31, 2014, NRLM diesel fuel produced by a transmix processor is subject to the standards under § 80.510(a). This paragraph (d) does not apply to NRLM diesel fuel that is sold or intended for sale in the areas listed in § 80.510(g)(1) or (g)(2).

(e) From June 1, 2014 and beyond, NRLM diesel fuel produced by a transmix processor is subject to the standards of § 80.510(c), except that LM diesel fuel is subject to the sulfur standard of § 80.510(a). This paragraph (e) does not apply to NRLM or LM diesel fuel that is sold or intended for sale in the areas listed in § 80.510(g)(1) or (g)(2).

■ 17. Section 80.520 is amended by revising paragraph (b) and removing paragraph (d) to read as follows:

§ 80.520 What are the standards and dye requirements for motor vehicle diesel fuel?

* * * * *

(b) *Dye requirements.* (1) All motor vehicle diesel fuel shall be free of visible evidence of dye solvent red 164 (which has a characteristic red color in diesel fuel), except for motor vehicle diesel fuel that is used in a manner that is tax exempt under section 4082 of the Internal Revenue Code. All motor vehicle diesel fuel shall be free of yellow solvent 124.

(2) Until June 1, 2010, any #1D or #2D distillate fuel that does not show visible evidence of dye solvent red 164 shall be considered to be motor vehicle diesel fuel and subject to all the requirements of this subpart for motor vehicle diesel fuel, except for distillate fuel designated or classified as any of the following:

(i) For use only in the State of Alaska, as provided under 40 CFR 69.51.

(ii) For use under a national security exemption under § 80.606 or for use only in a research and development testing program exempted under § 80.607.

(iii) For use in the U.S. Territories as provided under § 80.608.

(iv) Jet fuel meeting the definition under § 80.2.

(v) Kerosene meeting the definition under § 80.2.

(vi) Diesel fuel that is produced beginning June 1, 2006, with a sulfur level less than or equal to 500 ppm, and designated as NRLM or LM that has not yet been distributed from a truck loading terminal or bulk terminal to a retail outlet, wholesale purchaser-consumer or ultimate consumer.

* * * * *

■ 18. Section 80.521 is revised to read as follows:

§ 80.521 What are the standards and identification requirements for diesel fuel additives?

(a) Except as provided in paragraph (b) of this section, any diesel fuel additive that is added to, intended for adding to, used in, or offered for use in any MVNRLM diesel fuel subject to the 15 ppm sulfur content standards of § 80.510(b), § 80.510(c), or § 80.520(a) at any downstream location must—

(1) Have a sulfur content less than or equal to 15 ppm.

(2) Be accompanied by a product transfer document pursuant to § 80.591 indicating that the additive complies with the 15 ppm sulfur standard for diesel fuel, except for those diesel fuel additives which are only sold in containers for use by the ultimate consumer of diesel fuel and which are subject to the requirements of § 80.591(d).

(b) Any diesel fuel additive that is added to, intended for adding to, used in, or offered for use in diesel fuel subject to the 15 ppm sulfur content standards of § 80.510(b) or (c) or § 80.520(a) may have a sulfur content exceeding 15 ppm provided that each of the following conditions are met:

(1) The additive is added to or used in the diesel fuel in a quantity less than one percent by volume of the resultant additive/diesel fuel mixture;

(2) The product transfer document complies with the informational requirements of § 80.591; and

(3) The additive is not used or intended for use by an ultimate consumer in diesel motor vehicles or nonroad diesel engines.

■ 19. Section 80.522 is revised to read as follows:

§ 80.522 May used motor oil be dispensed into diesel motor vehicles or nonroad diesel engines?

No person may introduce used motor oil, or used motor oil blended with diesel fuel, into the fuel system of model year 2007 or later diesel motor vehicles or model year 2011 or later nonroad diesel engines (not including locomotive or marine diesel engines), unless both of the following requirements have been met:

(a) The vehicle or engine manufacturer has received a Certificate of Conformity under 40 CFR part 86, 40 CFR part 89, or 40 CFR part 1039 and the certification of the vehicle or engine configuration is explicitly based on emissions data with the addition of motor oil; and

(b) The oil is added in a manner and rate consistent with the conditions of the Certificate of Conformity.

■ 20. Section 80.523 is removed and reserved.

§ 80.523 [Removed and Reserved]

■ 21. Section 80.527 is revised to read as follows:

§ 80.527 Under what conditions may motor vehicle diesel fuel subject to the 15 ppm sulfur standard be downgraded to motor vehicle diesel fuel subject to the 500 ppm sulfur standard?

(a) *Definitions.* As used in this section, downgrade means changing the designation or classification of motor vehicle diesel fuel subject to the 15 ppm sulfur standard under § 80.520(a)(1) to motor vehicle diesel fuel subject to the 500 ppm sulfur standard under § 80.520(c). A downgrade occurs when the change in designation or classification takes place. Changing the designation or classification of motor vehicle diesel fuel subject to the 15 ppm sulfur standard under § 80.520(a)(1) to any designation or classification that is not a motor vehicle diesel fuel is not a downgrade for purposes of this section.

(b) *Who is subject to the downgrade limitation:* Any distributor, retailer, or wholesale purchaser consumer that takes custody of any diesel fuel designated or classified as #2D 15 ppm sulfur motor vehicle diesel fuel and delivers any diesel fuel designated or classified as #2D 500 ppm motor vehicle diesel fuel.

(c) *Downgrading limitation.* (1) Except as provided in paragraphs (d) and (e) of this section, a person described in paragraph (b) of this section may not downgrade a total of more than 20 percent of the #2D motor vehicle diesel fuel (by volume) that is subject to the 15 ppm sulfur standard of § 80.520(a)(1) to #2D motor vehicle diesel fuel subject to the sulfur standard of § 80.520(c) while such person has custody of such fuel.

(2) The limitation of paragraph (c)(1) of this section applies separately to each facility as defined under § 80.502 where there is custody of the fuel when it is downgraded.

(3) Compliance with the limitation of paragraph (c)(1) of this section applies separately for the compliance periods of October 1, 2006 through May 31, 2007; June 1, 2007 through June 30, 2008; July 1, 2008 through June 30, 2009; July 1, 2009 through May 31, 2010.

(4) Compliance with the limitation of paragraph (c)(1) of this section shall be as calculated under § 80.599(e).

(d) *Diesel fuel in violation of the 15 ppm standard.* Where motor vehicle diesel fuel subject to the 15 ppm sulfur standard of § 80.520(a)(1) is found to be in violation of any standard under § 80.520(a) and is consequently downgraded to 500 ppm sulfur motor vehicle diesel fuel, the person having custody of the fuel at the time it is found to be in violation must include the volume of such downgraded fuel toward its 20 percent volume limitation under paragraph (c)(1) of this section, unless the person demonstrates that it did not cause the violation.

(e) *Special provisions for retail outlets and wholesale purchaser-consumer facilities.* Notwithstanding the provisions of paragraph (c)(1) of this section, retailers and wholesale purchaser-consumers shall comply with the downgrading limitation as follows:

(1) Retailers and wholesale purchaser-consumers who sell, offer for sale, or dispense motor vehicle diesel fuel that is subject to the 15 ppm sulfur standard under § 80.520(a)(1) are exempt from the volume limitations of paragraph (c)(1) of this section.

(2) A retailer or wholesale purchaser-consumer who does not sell, offer for sale, or dispense motor vehicle diesel fuel subject to the 15 ppm sulfur standard under § 80.520(a)(1) must comply with the downgrading limitations of paragraph (c) of this section, and compliance shall be calculated as specified in § 80.599(e)(2).

(f) *Termination of downgrading limitations.* The provisions of this section shall not apply after May 31, 2010.

■ 22. Section 80.530 is revised to read as follows:

§ 80.530 Under what conditions can 500 ppm motor vehicle diesel fuel be produced or imported after May 31, 2006?

(a) Beginning June 1, 2006, a refiner or importer may produce or import motor vehicle diesel fuel subject to the 500 ppm sulfur content standard of § 80.520(c) if all of the following requirements are met:

(1) Each batch of motor vehicle diesel fuel subject to the 500 ppm sulfur content standard must be designated by the refiner or importer as subject to such standard, pursuant to § 80.598(a).

(2) The refiner or importer must meet the requirements for product transfer documents in § 80.590 for each batch subject to the 500 ppm sulfur content standard.

(3)(i) The volume of motor vehicle diesel fuel that is produced or imported during a compliance period (V_{500}, as provided in paragraph (a)(5) of this section, may not exceed the following volume limit:

(A) For the compliance periods prior to the period from July 1, 2009 through May 31, 2010, 20 percent of the volume of motor vehicle diesel fuel that is produced or imported during a compliance period (V_t) plus an additional volume of motor vehicle diesel fuel represented by credits properly generated and used pursuant to the requirements of §§ 80.531 and 80.532.

(B) For the compliance period from July 1, 2009 through May 31, 2010, 20 percent of the volume of motor vehicle diesel fuel that is produced or imported prior to January 1, 2010 during the compliance period (V_t), plus an additional volume of motor vehicle diesel fuel represented by credits properly generated and used pursuant to the requirements of §§ 80.531 and 80.532. From January 1, 2010 through May 31, 2010, the volume of motor vehicle diesel fuel that is produced or imported shall not exceed the volume represented by credits used pursuant to § 80.532.

(ii) The terms V_{500} and V_t have the meaning specified in § 80.531(a)(2).

(4) Compliance with the volume limit in paragraph (a)(3) of this section must be determined separately for each refinery. For an importer, such compliance must be determined separately for each Credit Trading Area (as defined in § 80.531) into which motor vehicle diesel fuel is imported. If a party is both a refiner and an importer, such compliance shall be determined separately for the refining and importation activities.

(5) Compliance with the volume limit in paragraph (a)(3) of this section shall be determined on an annual basis, where the annual compliance period is from July 1 through June 30. For the year 2006, compliance shall be determined for the period June 1, 2006 through June 30, 2007. For the year 2010, compliance shall be determined for the period of July 1, 2009 through May 31, 2010.

(6) Any motor vehicle diesel fuel produced or imported above the volume limit in paragraph (a)(3) of this section shall be subject to the 15 ppm sulfur content standard. However, for any compliance period prior to the compliance period July 1, 2009 through May 31, 2010, a refiner or importer may exceed the volume limit in paragraph (a)(3) of this section by no more than 5 percent of the volume of diesel fuel produced or imported during the compliance period (V_t), provided that

for the immediately following compliance period:

(i) The refiner or importer complies with the volume limit in paragraph (a)(3) of this section; and

(ii) The refiner or importer produces or imports a volume of motor vehicle diesel fuel subject to the 15 ppm sulfur standard, or obtains credits properly generated and used pursuant to the requirements of §§ 80.531 and 80.532 that represent a volume of motor vehicle diesel fuel, equal to the volume of the exceedance for the prior compliance period.

(b) After May 31, 2010, no refiner or importer may produce or import motor vehicle diesel fuel subject to the 500 ppm sulfur content standard pursuant to this section.

■ 23. Section 80.531 is amended by revising paragraphs (a)(1), (a)(2), (d)(1) (d)(5), (e)(1), and (e)(2)(i) to read as follows:

§ 80.531 How are motor vehicle diesel fuel credits generated?

(a) * * *

(1) A refiner or importer may generate credits during the period June 1, 2006 through December 31, 2009, for motor vehicle diesel fuel produced or imported that is designated as subject to the 15 ppm sulfur content standard under § 80.520(a)(1). Credits may be generated only if the volume of motor vehicle diesel fuel designated under § 80.598(a) as subject to the 15 ppm sulfur standard of § 80.520(a) exceeds 80 percent of the total volume of motor vehicle diesel fuel produced or imported as described in paragraph (a)(2) of this section.

(2) The number of motor vehicle diesel fuel credits generated shall be calculated for each compliance period (as specified in § 80.530(a)(5)) as follows:

$$C = V15_{15} - (0.80 \times V_t)$$

Where:

C = the positive number of motor vehicle diesel fuel credits generated, in gallons.

V_{15} = the total volume in gallons of diesel fuel produced or imported that is designated under § 80.598 as motor vehicle diesel fuel and subject to the standards of § 80.520(a) during the compliance period.

V_t n $=_{15} + V_{500}$.

V_{500} = the total volume in gallons of diesel fuel produced or imported that is designated under § 80.598(a) as motor vehicle diesel fuel and subject to the 500 ppm sulfur standard under § 80.520(c) plus the total volume of any other diesel fuel (not including V_{15}, diesel fuel that is dyed in accordance with § 80.520(b) at the refinery or import facility where the diesel fuel is produced or imported, or diesel fuel that is designated as NRLM under § 80.598(a)) represented as having a sulfur content less than or equal to 500 ppm.

* * * * *

(d) * * *

(1) The designation requirements of § 80.598, and all recordkeeping and reporting requirements of §§ 80.592, 80.593, 80.594, 80.600, and 80.601.

* * * * *

(5) In addition to the reporting requirements under paragraph (d)(1) of this section, the refiner or importer must submit a report to the Administrator no later than August 31, 2005 for the period from June 1, 2004 through May 31, 2005, or August 31, 2006 for the period from June 1, 2005 through May 31, 2006, demonstrating that all the motor vehicle diesel fuel produced or imported for which credits were generated met the applicable requirements of paragraph (b), (c), or (d)(4) of this section. If the Administrator finds that such credits did not in fact meet the requirements of paragraphs (b)(1) and (c)(1) of this section, as applicable, or if the Administrator determines that there is insufficient information to determine the validity of such credits, the Administrator may deny the credits submitted in whole or in part.

(e) * * *

(1) Notwithstanding the provisions of paragraph (a) of this section, a small refiner that is approved by the EPA as a small refiner under § 80.551(g) may generate credits under § 80.552(b). Such a small refiner may generate one credit for each gallon of motor vehicle diesel fuel produced that is designated under § 80.598 as motor vehicle diesel fuel subject to the 15 ppm sulfur standard under § 80.520(a)(1).

(2) * * *

(i) Credits may be generated under this paragraph (e) and § 80.552(b) only during the compliance periods beginning June 1, 2006 and ending on May 31, 2010, however diesel fuel produced after December 31, 2009 shall not generate credits. Credits shall be designated separately by refinery, separately by CTA of generation, and separately by annual compliance period. The annual compliance period for 2006 shall be June 1, 2006 through June 30, 2007. The annual compliance period for 2010 shall be July 1, 2009 through May 31, 2010.

* * * * *

■ 24. Section 80.532 is revised to read as follows:

§ 80.532 How are motor vehicle diesel fuel credits used and transferred?

(a) *Credit use stipulations.* Motor vehicle diesel fuel credits generated under § 80.531 may be used to meet the volume limit of § 80.530(a)(3) provided that:

(1) The motor vehicle diesel fuel credits were generated and reported according to the requirements of this subpart; and

(2) The conditions of this section are met.

(b) *Use of credits generated under § 80.531.* Motor vehicle diesel fuel credits generated under § 80.531 may be used by a refiner or by an importer to comply with § 80.530 by applying one credit for every gallon of motor vehicle diesel fuel needed to meet compliance with the volume limit of § 80.530(a)(3).

(c) *Credit banking.* Motor vehicle diesel fuel credits generated may be banked for use or transfer in a later compliance period or may be transferred to another refiner or importer for use as provided in paragraph (d) of this section.

(d) *Credit transfers.* (1) Motor vehicle diesel fuel credits obtained from another refiner or from another importer, including early motor vehicle diesel fuel credits and small refiner motor vehicle diesel fuel credits as described in § 80.531(b) through (e), may be used to satisfy the volume limit of § 80.530(a)(3) if all the following conditions are met:

(i) The motor vehicle diesel fuel credits were generated in the same CTA as the CTA in which motor vehicle diesel fuel credits are used to achieve compliance;

(ii) The motor vehicle diesel fuel credits are used in compliance with the time period limitations for credit use in this subpart;

(iii) Any credit transfer takes place no later than the August 31 following the compliance period when the motor vehicle diesel fuel credits are used;

(iv) No credit may be transferred more than twice, as follows: The first transfer by the refiner or importer who generated the credit may only be made to a refiner or importer who intends to use the credit; if the transferee cannot use the credit, it may make a second and final transfer only to a refiner or importer who intends to use the credit. In no case may a credit be transferred more than twice before being used or terminated;

(v) The credit transferor must apply any motor vehicle diesel fuel credits necessary to meet the transferor's annual compliance requirements before transferring motor vehicle diesel fuel credits to any other refinery or importer;

(vi) No motor vehicle diesel fuel credits may be transferred that would result in the transferor having a negative credit balance; and

(vii) Each transferor must supply to the transferee records indicating the year the motor vehicle diesel fuel credits were generated, the identity of the refiner (and refinery) or importer who generated the motor vehicle diesel fuel credits, the CTA of credit generation, and the identity of the transferring entity, if it is not the same entity who generated the motor vehicle diesel fuel credits.

(2) In the case of motor vehicle diesel fuel credits that have been calculated or created improperly, or are otherwise determined to be invalid, the following provisions apply:

(i) Invalid motor vehicle diesel fuel credits cannot be used to achieve compliance with the transferee's volume requirements regardless of the transferee's good faith belief that the motor vehicle diesel fuel credits were valid.

(ii) The refiner or importer who used the motor vehicle diesel fuel credits, and any transferor of the motor vehicle diesel fuel credits, must adjust their credit records, reports and compliance calculations as necessary to reflect the proper motor vehicle diesel fuel credits.

(iii) Any properly created motor vehicle diesel fuel credits existing in the transferor's credit balance after correcting the credit balance, and after the transferor applies motor vehicle diesel fuel credits as needed to meet the compliance requirements at the end of the compliance period, must first be applied to correct the invalid transfers before the transferor trades or banks the motor vehicle diesel fuel credits.

(e) *Limitations on credit use.* (1) Motor vehicle diesel fuel credits may not be used to achieve compliance with any requirements of this subpart other than the volume limit of § 80.530(a)(3), unless specifically approved by the Administrator pursuant to a hardship relief petition under § 80.560 or 80.561.

(2) A refiner or importer possessing motor vehicle diesel fuel credits must use all motor vehicle diesel fuel credits in its possession prior to applying the credit deficit provisions of § 80.530(a)(6).

(3) No motor vehicle diesel fuel credits may be used to meet compliance with this subpart subsequent to the compliance period ending May 31, 2010.

■ 25. A new § 80.533 is added to read as follows:

§ 80.533 How does a refiner or importer apply for a motor vehicle or non-highway baseline?

(a) A refiner or importer wishing to generate credits under § 80.535 or use the small refiner provisions under § 80.554 must submit an application to EPA that includes the information required under paragraph (c) of this section by the dates specified in paragraph (f) of this section. A refiner must apply for a motor vehicle baseline for each refinery in order to generate credits under § 80.535 and apply for a non-highway baseline for each refinery to use the provisions of § 80.554 (a), (b), or (d).

(b) The baseline must be sent to the following address: U.S. EPA—Attn: Nonroad Rule Diesel Fuel Baseline, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460 (regular mail) or U.S. EPA, Attn: Nonroad Rule Diesel Fuel Baseline, Transportation and Regional Programs Division (6406J), 1310 L Street, NW., 6th floor, Washington, DC 20005 (express mail).

(c) A baseline application must be submitted for each refinery or import facility and include the following information:

(1) A listing of the names and addresses of all refineries or import facilities owned by the company for which the refiner or importer is applying for a motor vehicle or non-highway baseline.

(2)(i) For purposes of a motor vehicle baseline volume for use in determining early credits per § 80.535(a) and (b) and for purposes of a non-highway baseline volume used in determining compliance with the provisions of § 80.554(a) or (d), the baseline volume produced during the three calendar years beginning January 1, 2003, 2004, and 2005, as calculated under paragraph (e)(1) of this section.

(ii) For purposes of a motor vehicle baseline volume for use in determining early credits per § 80.535(c) and for purposes of a non-highway baseline volume used in determining compliance with the provisions of § 80.554(b), the baseline volumes produced during the three calendar years beginning January 1, 2006, 2007, and 2008, as calculated under paragraph (e)(2) of this section.

(3) A letter signed by the president, chief operating officer of the company, or his/her delegate, stating that the information contained in the motor vehicle or non-highway baseline application is true to the best of his/her knowledge.

(4) Name, address, phone number, facsimile number and e-mail address of a corporate contact person.

(5) For each batch of diesel fuel produced or imported during each calendar year:

(i) The date that production was completed or importation occurred for the batch and the batch designation or classification.

(ii) The batch volume.

(6) Other appropriate information as requested by EPA.

(d) *Calculation of the Motor vehicle Baseline,* B_{MV}. (1) Under paragraph (c)(2)(i) of this section, B_{MV} equals the average annual volume of motor vehicle diesel fuel produced or imported from January 1, 2003 through December 31, 2005.

(2) Under paragraph (c)(2)(ii) of this section, B_{MV} equals the average annual volume of motor vehicle diesel fuel produced during the period from January 1, 2006 through December 31, 2008.

(3) For purposes of this paragraph, fuel produced for export, jet fuel (kerosene), and fuel specifically produced to meet military specifications (such as JP–4, JP–8, and F–76), shall not be included in baseline calculations.

(e) *Calculation of the Non-highway Baseline,* B_{NRLM}. (1) Under paragraph (c)(2)(i) of this section, B_{NRLM} equals the average annual volume of all #2D distillate produced or imported from January 1, 2003 through December 31, 2005, less B_{MV} as determined in paragraph (d)(1) of this section.

(2) Under paragraph (c)(2)(ii) of this section, $_{NRLM}$ equals the average annual volume of MVNRLM produced or imported from January 1, 2006 through December 31, 2008, less B_{MV} as determined in paragraph (d)(2) of this section.

(3) For purposes of this paragraph (e), fuel produced for export, jet fuel, kerosene, and fuel specifically produced to meet military specification (such as JP–4, JP–8, and F–76), shall not be included in baseline calculations.

(f)(1) Applications submitted under paragraph (c)(2)(i) of this section must be postmarked by February 28, 2006.

(2) Applications submitted under paragraph (c)(2)(ii) of this section must be postmarked by February 28, 2009.

(g)(1) For applications submitted under paragraph (c)(2)(i) of this section, EPA will notify refiners or importers by June 1, 2006 of approval of the baselines for each of the refiner's refineries or importer's import facilities or of any deficiencies in the refiner's or importer's application.

(2) For applications submitted under paragraph (c)(2)(ii) of this section, EPA will notify refiners or importers by June 1, 2009 regarding approval of the baselines for each of the refiner's refineries or importer's import facilities of any deficiencies in the refiner's or importer's application.

(h) If at any time the motor vehicle baseline or non-highway baseline submitted in accordance with the requirements of this section is determined to be incorrect, EPA will notify the refiner or importer of the corrected baseline and any compliance calculations made on the basis of that baseline will have to be adjusted retroactively.

■ 26. A new § 80.535 is added to read as follows.

§ 80.535 How are NRLM diesel fuel credits generated?

(a) *Generation of high sulfur NRLM credits from June 1, 2006 through May 31, 2007.* (1) During the period June 1, 2006 through May 31, 2007, a refiner or importer may generate credits pursuant to the provisions of this section if all of the following conditions are met:

(i) The refiner or importer notifies EPA of its intention to generate credits and the period during which it will generate credits. This notification must be received by EPA at least 120 calendar days prior to the date it begins generating credits under this section.

(ii) Each batch or partial batch of NRLM diesel fuel for which credits are claimed shall be subject to all of the provisions of this subpart for NRLM diesel fuel as if it had been produced after June 1, 2007 and before June 1, 2010.

(iii) The number of high-sulfur NRLM credits (HSC) that are generated shall be a positive number.

(2) The refiner or importer shall choose one of the following methods for calculating credits for each calculation period.

(i) For fuel that is dyed under the provisions of § 80.520, HSC equals the volume of fuel in gallons produced or imported during the period identified in paragraph (a)(1) of this section that is designated as NRLM diesel fuel and that is subject to and complies with the provisions of § 80.510(a); or

(ii) For dyed or undyed fuel that complies with the provisions of § 80.598 for a calculation period of June 1, 2006 through May 31, 2007, determine HSC as follows:

$$HSC = V_{510} + V_{520} - B_{MV}$$

Where:

V_{510} = The total volume of NRLM diesel fuel produced or imported during the annual calculation period that complies with the standards of § 80.510(a) or (b).

V_{520} = The total volume of motor vehicle diesel fuel produced or imported during the annual calculation period that complies with the standards of § 80.520(a) or (c).

B_{MV} = As calculated in § 80.533(d)(1).

(3) High-sulfur NRLM credits shall be generated and designated as follows:

(i) Credits shall be generated separately for each refiner or importer.

(ii) Credits may not be generated by both a foreign refiner and by an importer for the same motor vehicle diesel fuel.

(iii) Credits shall not be generated under both § 80.531 and this section for the same diesel fuel.

(iv) Any credits generated by a foreign refiner shall be generated as provided in § 80.620(c) and this section.

(4) No credits may be generated under this paragraph (a) after May 31, 2007.

(5) Any fuel for which a refiner or importer wishes to generate credits must be designated as 500 ppm sulfur NRLM diesel fuel when delivered to the next entity. The refiner may not designate the fuel as 500 ppm sulfur with the intent that it be mixed by the next entity with a batch of distillate with a higher sulfur level to create a fuel with a classification other than 500 ppm sulfur or the classification of the fuel it is mixed with (*e.g.*, it cannot mix fuel designated as 500 ppm sulfur with fuel classified as high sulfur to produce a fuel classified as 2000 ppm sulfur to meet state or local sulfur limits).

(6) The refiner or importer must submit a report to the Administrator no later than July 31, 2007. The report must demonstrate that all the NRLM diesel fuel produced or imported which generated credits met the applicable requirements of paragraphs (a)(1) through (a)(5) of this section. If the Administrator finds that such credits did not in fact meet the requirements of paragraphs (a)(1) through (a)(5) of this section, as applicable, or if the Administrator determines that there is insufficient information to determine the validity of such credits, the Administrator may deny the credits submitted in whole or in part.

(b) *Generation of high-sulfur NRLM credits by small refiners from June 1, 2006 through May 31, 2010.* (1) Notwithstanding the dates specified in paragraph (a) of this section, during the period from June 1, 2006 through May 31, 2010, a refiner that is approved by the EPA as a small refiner under § 80.551 may generate credits under paragraph (a) of this section during any compliance period as specified under § 80.599(a)(2) for diesel fuel produced or imported that is designated as NRLM diesel fuel and complies with the provisions of § 80.510(a).

(2) The small refiner must submit a report to the Administrator no later than August 31 after the end of each calculation period during which credits were generated. The report must demonstrate that all the NRLM diesel fuel produced or imported which generated credits met the applicable requirements of paragraphs (a)(1) through (a)(5) of this section. If the Administrator finds that such credits did not in fact meet the requirements of paragraphs (a)(1) through (a)(5) of this section, as applicable, or if the Administrator determines that there is insufficient information to determine the validity of such credits, the Administrator may deny the credits submitted in whole or in part.

(3) In addition, a foreign refiner that is approved by the Administrator to generate credits under § 80.554 shall comply with the requirements of § 80.620.

(c) *Generation of 500 ppm sulfur NRLM credits from June 1, 2009 through May 31, 2010.* (1) During the period of June 1, 2009 through May 31, 2010, a refiner or importer may generate credits pursuant to the provisions of this section if all of the following conditions are met:

(i) The refiner or importer notifies EPA of its intention to generate credits and the period during which it will generate credits. This notification must be received by EPA at least 120 calendar days prior to the date it begins generating credits under this section.

(ii) Each batch or partial batch of NRLM diesel fuel for which credits are claimed shall be subject to all of the provisions of this subpart for NRLM diesel fuel as if it had been produced after June 1, 2010.

(iii) The number of 500 ppm sulfur NRLM credits in gallons that are generated, C_{500}, shall be a positive number calculated as follows:

$$C500 = V_{15} - B_{MV}$$

Where:

V_{15} = The total volume in gallons of 15 ppm diesel fuel produced or imported during the period stated under paragraph (c)(1)(i) of this section that is designated as either motor vehicle diesel fuel or NRLM diesel fuel.

B_{MV} = As determined in § 80.533(d)(2).

(2) 500 ppm sulfur NRLM credits shall be generated and designated as follows:

(i) Credits shall be generated separately for each refiner or importer.

(ii) Credits may not be generated by both a foreign refiner and by an importer for the same diesel fuel.

(iii) Credits shall not be generated under both § 80.531 and this section for the same diesel fuel.

(iv) Any credits generated by a foreign refiner shall be generated as provided in § 80.620(c) and this section.

(3) No credits may be generated under this paragraph (c) after May 31, 2010.

(4) The refiner or importer must submit a report to the Administrator no later than August 31, 2010. The report must demonstrate that all the 15 ppm sulfur NRLM diesel fuel produced or imported which generated credits met

the applicable requirements of paragraphs (c)(1) through (c)(3) of this section. If the Administrator finds that such credits did not in fact meet the requirements of paragraphs (c)(1) through (c)(3) of this section, as applicable, or if the Administrator determines that there is insufficient information to determine the validity of such credits, the Administrator may deny the credits submitted in whole or in part.

(d) *Generation of 500 ppm sulfur NRLM credits by small refiners from June 1, 2009 through December 31, 2013.* (1) Notwithstanding the dates specified in paragraph (c) of this section, during the period from June 1, 2009 through December 31, 2013, a refiner that is approved by the EPA as a small refiner under § 80.551 may generate credits under paragraph (c) of this section during any compliance period as specified under § 80.599(a)(2) for diesel fuel produced or imported that is designated as NR or NRLM diesel fuel and complies with the provisions of § 80.510(b) or (c).

(2) The small refiner must submit a report to the Administrator no later than August 31 after the end of each calculation period during which credits were generated. The report must demonstrate that all the 15 ppm sulfur NR or NRLM diesel fuel produced or imported for which credits were generated met the applicable requirements of paragraphs (c)(1) through (c)(3) of this section. If the Administrator finds that such credits did not in fact meet the requirements of paragraphs (c)(1) through (c)(3) of this section, as applicable, or if the Administrator determines that there is insufficient information to determine the validity of such credits, the Administrator may deny the credits submitted in whole or in part.

(3) In addition, a foreign refiner that is approved by the Administrator to generate credits under § 80.554 shall comply with the requirements of § 80.620.

■ 27. A new § 80.536 is added to read as follows:

§ 80.536 How are NRLM diesel fuel credits used and transferred?

(a) *Credit use stipulations.* Credits generated under § 80.535(a) and (b) may be used to meet the NRLM diesel fuel sulfur standard of § 80.510(a), and credits generated under 80.535(c) and (d) may be used to meet the NR and NRLM diesel fuel sulfur standard of 80.510(b) and (c), respectively, provided that:

(1) The credits were generated and reported according to the requirements of this subpart; and

(2) The conditions of this section are met.

(b) *Using credits generated under § 80.535.* Credits generated under § 80.535 may be used by a refiner or an importer to comply with the diesel fuel standards of § 80.510 (a), (b), and (c) by applying one credit for every gallon of diesel fuel that does not comply with the applicable standard.

(c) *Credit banking.* Credits generated may be banked for use at a later time or may be transferred to any other refiner or importer nationwide for use as provided in paragraph (d) of this section.

(d) *Credit transfers.* (1) Credits generated under § 80.535 that are obtained from another refiner or importer may be used to comply with the diesel fuel sulfur standards of § 80.510(a), (b), and (c) if all the following conditions are met:

(i) The credits are used in compliance with the time period limitations for credit use in this subpart;

(ii) Any credit transfer is completed no later than August 31 following the compliance period when the credits are used to comply with a standard under paragraph (a) of this section;

(iii) No credit is transferred more than twice, as follows:

(A) The first transfer by the refiner or importer who generated the credit may only be made to a refiner or importer that intends to use the credit; if the transferee cannot use the credit, it may make a second and final transfer only to a refiner or importer who intends to use the credit; and

(B) In no case may a credit be transferred more than twice before it is used or it expires;

(iv) The credit transferor applies any credits necessary to meet the transferor's annual compliance requirements before transferring credits to any other refinery or importer;

(v) No credits are transferred that would result in the transferor having a negative credit balance; and

(vi) Each transferor supplies to the transferee records indicating the year the credits were generated, the identity of the refiner (and refinery) or importer that generated the credits, and the identity of the transferor, if it is not the same party that generated the credits.

(2) In the case of credits that have been calculated or created improperly, or are otherwise determined to be invalid, the following provisions apply:

(i) Invalid credits cannot be used to achieve compliance with the transferee's volume requirements regardless of the transferee's good faith belief that the credits were valid.

(ii) The refiner or importer that used the credits, and any transferor of the credits, must adjust its credit records, reports and compliance calculations as necessary to reflect the proper credits.

(iii) Any properly created credits existing in the transferor's credit balance after correcting the credit balance, and after the transferor applies credits as needed to meet the compliance requirements at the end of the calendar year, must first be applied to correct the invalid transfers before the transferor trades or banks the credits.

(e) *General limitation on credit use.* Credits may not be used to achieve compliance with any requirements of this subpart other than the standards of § 80.510(a), (b), and (c), unless specifically approved by the Administrator pursuant to a hardship relief petition under § 80.560 or § 80.561.

(f) *Use of high sulfur NRLM credits.* (1) High sulfur NRLM credits generated under § 80.535(a) or (b) may be used on a one-for-one basis to meet the NRLM diesel fuel sulfur standard of § 80.510(a) from June 1, 2007 through May 31, 2010. For example, one credit generated by the production or importation of one gallon of NRLM diesel fuel subject to the NRLM diesel fuel sulfur standard of § 80.510 (a) may be used to produce or import one gallon of NRLM diesel fuel that is exempt from the sulfur standard of § 80.510(a) during the period from June 1, 2007 through May 31, 2010.

(2) Any high sulfur NRLM diesel fuel produced after June 1, 2007 through the use of credits must—

(i) Be dyed red under the provisions of § 80.520 at the point of production or importation;

(ii) Be associated with a product transfer document that bears a unique product code as specified in § 80.590; and

(iii) Not be used to sell or deliver diesel fuel into areas specified in § 80.510(g)(1) or (g)(2).

(3) No high sulfur NRLM credits may be used subsequent to the compliance period ending May 31, 2010.

(4) Any high sulfur NRLM credits not used under the provisions of paragraph (f)(1) of this section may be converted into 500 ppm sulfur NRLM credits on a one-for-one basis for use under paragraph (g) of this section.

(g) *Use of 500 ppm sulfur NRLM credits.* (1) 500 ppm sulfur NRLM credits generated under § 80.535(c) or (d) or converted from high sulfur NRLM credits under paragraph (f)(3) of this section may be used on a one-for-one basis to meet the NR or NRLM diesel fuel sulfur standards of § 80.510(b) or (c) from June 1, 2010 through May 31, 2014. For example, one credit generated by the production or importation of one gallon of NRLM diesel fuel subject to the NRLM diesel fuel sulfur standard of § 80.510 (c) may be used to produce or import one gallon of NR diesel fuel that is subject to the sulfur standard of § 80.510(a) during the period from June 1, 2010 through May 31, 2014.

(2) Any 500 ppm sulfur NR or NRLM diesel fuel produced or imported after June 1, 2010 through the use of these credits must—

(i) Bear a unique product code as specified in § 80.590; and

(ii) Not be used to sell or deliver diesel fuel into areas specified in § 80.510(g)(1) or (g)(2).

(3) No 500 ppm sulfur NRLM credits may be used after May 31, 2014.

■ 28. Section 80.540 is amended by revising paragraphs (b), (d), (e), and (f) to read as follows:

§ 80.540 How may a refiner be approved to produce gasoline under the GPA gasoline sulfur standards in 2007 and 2008?

* * * * *

(b) The refiner must submit an application in accordance with the provisions of §§ 80.595 and 80.596. The application must also include information, as provided in § 80.594(c), demonstrating that starting no later than June 1, 2006, 95 percent of the motor vehicle diesel fuel produced by the refinery for United States use will comply with the 15 ppm sulfur standard under § 80.520(a)(1), and that the volume of motor vehicle diesel fuel produced will comply with the volume requirements of paragraph (e) of this section.

* * * * *

(d) From June 1, 2006 through December 31, 2008, 95 percent of the motor vehicle diesel fuel produced by a refiner that has been approved under paragraph (c) of this section to produce gasoline subject to the GPA gasoline sulfur standards in 2007 and 2008, must be accurately designated under § 80.598 as meeting the 15 ppm sulfur standard of § 80.520(a)(1).

(e) The total volume of motor vehicle diesel fuel produced for use in the United States and designated as meeting the 15 ppm sulfur standard under paragraph (d) of this section must meet or exceed 85 percent of the baseline volume established under paragraph (c) of this section, except that for the first compliance period from June 1, 2006 through June 30, 2007, the total volume must meet or exceed 92 percent of the baseline volume.

(f) Compliance with the volume requirements in paragraph (e) of this section shall be determined each compliance period. Annual compliance periods shall be from July 1 through June 30. For the year 2006, the compliance period shall be from June 1, 2006 through June 30, 2007.

* * * * *

■ 29. Section 80.550 is amended by revising the section heading and paragraphs (a), (b), (c), (d), (e) and (f) to read as follows:

§ 80.550 What is the definition of a motor vehicle diesel fuel small refiner or a NRLM diesel fuel small refiner under this subpart?

(a) A motor vehicle diesel fuel small refiner is defined as any person, as defined by 42 U.S.C. 7602(e), who—

(1) Produces diesel fuel at a refinery by processing crude oil through refinery processing units; and

(2) Employed an average of no more than 1,500 people, based on the average number of employees for all pay periods from January 1, 1999, to January 1, 2000; and

(3) Had an average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 1999; or

(4) Has been approved by EPA as a small refiner under § 80.235 and continues to meet the criteria of a small refiner under § 80.225.

(b) A NRLM diesel fuel small refiner is defined as any person, as defined by 42 U.S.C. 7602(e), who—

(1) Produces diesel fuel at a refinery by processing crude oil through refinery processing units;

(2) Employed an average of no more than 1,500 people, based on the average number of employees for all pay periods from January 1, 2002, to January 1, 2003; and

(3) Had an average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2003.

(c) Determine the number of employees and crude oil capacity under paragraphs (a) or (b) of this section, as follows:

(1) The refiner shall include the employees and crude oil capacity of any subsidiary companies, any parent company and subsidiaries of the parent company in which the parent has 50 percent or greater ownership, and any joint venture partners.

(2) For any refiner owned by a governmental entity, the number of employees and total crude oil capacity as specified in paragraph (a) of this section shall include all employees and crude oil production of the government to which the governmental entity is a part.

(3) Any refiner owned and controlled by an Alaska Regional or Village Corporation organized pursuant to the Alaska Native Claims Settlement Act (43 U.S.C. 1601) is not considered an affiliate of such entity, or with other concerns owned by such entity solely because of their common ownership.

(d)(1) Notwithstanding the provisions of paragraph (a) of this section, a refiner that acquires or reactivates a refinery that was shut down or non-operational between January 1, 1999, and January 1, 2000, may apply for motor vehicle diesel fuel small refiner status in accordance with the provisions of § 80.551(c)(1)(ii).

(2) Notwithstanding the provisions of paragraph (b) of this section, a refiner that acquires or reactivates a refinery that was shutdown or non-operational between January 1, 2002, and January 1, 2003, may apply for NRLM diesel fuel small refiner status in accordance with the provisions of § 80.551(c)(2)(ii).

(e) The following are ineligible for the small refiner provisions:

(1)(i) For motor vehicle diesel fuel, refiners with refineries built or started up after January 1, 2000.

(ii) For NRLM diesel fuel, refiners with refineries built or started up after January 1, 2003.

(2)(i) For motor vehicle diesel fuel, persons who exceed the employee or crude oil capacity criteria under this section on January 1, 2000, but who meet these criteria after that date, regardless of whether the reduction in employees or crude oil capacity is due to operational changes at the refinery or a company sale or reorganization.

(ii) For NRLM diesel fuel, persons who exceed the employee or crude oil capacity criteria under this section on January 1, 2003, but who meet these criteria after that date, regardless of whether the reduction in employees or crude oil capacity is due to operational changes at the refinery or a company sale or reorganization.

(3) Importers.

(4) Refiners who produce motor vehicle diesel fuel or NRLM diesel fuel other than by processing crude oil through refinery processing units.

(f)(1)(i) Refiners who qualify as motor vehicle diesel fuel small refiners under this section and subsequently cease production of diesel fuel from processing crude oil through refinery processing units, or employ more than 1,500 people or exceed the 155,000 bpcd crude oil capacity limit after January 1, 2004 as a result of merger with or acquisition of or by another entity, are disqualified as small refiners, except as provided for under paragraph (f)(4) of this section. If disqualification occurs, the refiner shall notify EPA in writing no later than 20 days following this disqualifying event.

(ii) Except as provided under paragraph (f)(3) of this section, any refiner whose status changes under this paragraph shall meet the applicable standards of § 80.520 within a period of up to 30 months from the disqualifying event for any of its refineries that were previously subject to the small refiner standards of § 80.552, but no later than the May 31, 2010.

(2)(i) Refiners who qualify as NRLM diesel fuel small refiners under this section and subsequently cease production of diesel fuel from crude oil, or employ more than 1,500 people or exceed the 155,000 bpcd crude oil capacity limit after January 1, 2004 as a result of merger with or acquisition of or by another entity, are disqualified as small refiners, except as provided for under paragraph (f)(4) of this section. If disqualification occurs, the refiner shall notify EPA in writing no later than 20 days following this disqualifying event.

(ii) Except as provided under paragraph (f)(3) of this section, any refiner whose status changes under this paragraph shall meet the applicable standards of § 80.510 within a period of up to 30 months of the disqualifying event for any of its refineries that were previously subject to the small refiner standards of § 80.552, but no later than the dates specified in § 80.554(a) or (b), as applicable.

(3) A refiner may apply to EPA for up to an additional six months to comply with the standards of § 80.510 or § 80.520 if more than 30 months would be required for the necessary engineering, permitting, construction, and start-up work to be completed. Such applications must include detailed technical information supporting the need for additional time. EPA will base a decision to approve additional time on information provided by the refiner and on other relevant information. In no case will EPA extend the compliance date beyond May 31, 2010 for a motor vehicle diesel fuel small refiner or beyond the dates specified in § 80.554(a) or (b), as applicable, for a NRLM diesel fuel small refiner.

(4) Disqualification under paragraphs (f)(1) or (f)(2) of this section shall not apply in the case of a merger between two previously approved small refiners.

(5) During the period of time up to 30 months provided under paragraph (f)(1)(ii) of this section, and any extension provided under paragraph (f)(3) of this section, the refiner may not generate motor vehicle diesel fuel sulfur credits under § 80.531(e). During the period of time up to 30 months provided under paragraph (f)(2)(ii) of this section, and any extension provided under paragraph (f)(3) of this section, the refiner may not generate NRLM diesel fuel sulfur credits under § 80.535(b) or (d).

* * * * *

■ 30. Section 80.551 is revised to read as follows:

§ 80.551 How does a refiner obtain approval as a small refiner under this subpart?

(a)(1)(i) Applications for motor vehicle diesel fuel small refiner status must be submitted to EPA by December 31, 2001.

(ii) Applications for NRLM diesel fuel small refiner status must be submitted to EPA by December 31, 2004.

(2)(i) In the case of a refiner who acquires or reactivates a refinery that was shutdown or non-operational between January 1, 1999, and January 1, 2000, the application for motor vehicle diesel fuel small refiner status must be submitted to EPA by June 1, 2003.

(ii) In the case of a refiner who acquires or reactivates a refinery that was shutdown or non-operational between January 1, 2002, and January 1, 2003, the application for NRLM diesel fuel small refiner status must be submitted to EPA by June 1, 2006.

(b) Applications for small refiner status must be sent via certified mail with return receipt or express mail with return receipt to: U.S. EPA—Attn: Diesel Small Refiner Status (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460 (certified mail/ return receipt) or Attn: Diesel Small Refiner Status, Transportation and Regional Programs Division, 1310 L Street, NW., 6th floor, Washington, DC 20005 (express mail/return receipt).

(c) The small refiner status application must contain the following information for the company seeking small refiner status, plus any subsidiary companies, any parent company and subsidiaries of the parent company in which the parent has 50 percent or greater ownership, and any joint venture partners:

(1) For motor vehicle diesel fuel small refiners—

(i) A listing of the name and address of each location where any employee worked during the 12 months preceding January 1, 2000; the average number of employees at each location based upon the number of employees for each pay period for the 12 months preceding January 1, 2000; and the type of business activities carried out at each location; or

(ii) In the case of a refiner who acquires or reactivates a refinery that was shutdown or non-operational between January 1, 1999, and January 1, 2000, a listing of the name and address of each location where any employee of the refiner worked since the refiner acquired or reactivated the refinery; the average number of employees at any such acquired or reactivated refinery during each calendar year since the refiner acquired or reactivated the refinery; and the type of business activities carried out at each location.

(2) For NRLM diesel fuel small refiners—

(i) A listing of the name and address of each location where any employee worked during the 12 months preceding January 1, 2003; the average number of employees at each location based upon the number of employees for each pay period for the 12 months preceding January 1, 2003; and the type of business activities carried out at each location; or

(ii) In the case of a refiner who acquires or reactivates a refinery that was shutdown or non-operational between January 1, 2002, and January 1, 2003, a listing of the name and address of each location where any employee of the refiner worked since the refiner acquired or reactivated the refinery; the average number of employees at any such acquired or reactivated refinery during each calendar year since the refiner acquired or reactivated the refinery; and the type of business activities carried out at each location.

(3) The total corporate crude oil capacity of each refinery as reported to the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) for the most recent 12 months of operation. The information submitted to EIA is presumed to be correct. In cases where a company disagrees with this information, the company may petition EPA with appropriate data to correct the record when the company submits its application for small refiner status. EPA may accept such alternate data at its discretion.

(4) For motor vehicle diesel fuel, an indication of whether the refiner, for each refinery, is applying for—

(i) The ability to produce motor vehicle diesel fuel subject to the 500 ppm sulfur standard under § 80.520(c) or generate credits under § 80.531, pursuant to the provisions of § 80.552(a) or (b); or

(ii) An extension of the duration of its small refiner gasoline sulfur standard under § 80.553, pursuant to the provisions of § 80.552(c).

(5) For NRLM diesel fuel, an indication of whether the refiner, for each refinery, is applying for—

(i) The ability to delay compliance under § 80.554(a) or (b), or to generate

NRLM diesel sulfur credits under § 80.535(b) or (d), pursuant to the provisions of § 80.554(c); or

(ii) An adjustment to its small refiner gasoline sulfur standards under § 80.240(a), pursuant to the provisions of § 80.554(d).

(6) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the application is true to the best of his/her knowledge.

(7) Name, address, phone number, facsimile number and e-mail address (if available) of a corporate contact person.

(d) For joint ventures, the total number of employees includes the combined employee count of all corporate entities in the venture.

(e) For government-owned refiners, the total employee count includes all government employees.

(f) Approval of small refiner status for refiners who apply under § 80.550(e) will be based on all information submitted under paragraph (c) of this section, except as provided in § 80.550(e).

(g) EPA will notify a refiner of approval or disapproval of small refiner status by letter. If disapproved, the refiner must comply with the sulfur standards in § 80.510 or 80.520, as appropriate, except as otherwise provided in this subpart.

(h) If EPA finds that a refiner provided false or inaccurate information on its application for small refiner status, upon notice from EPA the refiner's small refiner status will be void *ab initio*.

(i) Upon notification to EPA, an approved small refiner may withdraw its status as a small refiner. Effective on January 1 of the year following such notification, the small refiner will become subject to the sulfur standards in § 80.510 or 80.520, as appropriate, unless one of the other hardship provisions of this subpart apply.

■ 31. Section 80.552 is amended by revising the section heading and paragraphs (a), (b), (c), and (e) to read as follows:

§ 80.552 What compliance options are available to motor vehicle diesel fuel small refiners?

(a) A refiner that has been approved by EPA as a motor vehicle diesel fuel small refiner under § 80.551(g) may produce motor vehicle diesel fuel subject to the 500 ppm sulfur standard pursuant to the provisions of § 80.530, except that the volume limits of § 80.530(a)(3) shall only apply to that volume of diesel fuel that is produced or imported during an annual compliance period that exceeds 105 percent of the baseline volume established under § 80.595 (V_{500}). The annual compliance period shall be from July 1 through June 30. For the year 2006, the compliance period shall be from June 1, 2006 through June 30, 2007, and the volume limits shall only apply to that volume V_{500} that exceeds 113 percent of the baseline volume.

(b) A refiner that has been approved by EPA as a motor vehicle diesel fuel small refiner under § 80.551(g) may generate motor vehicle diesel fuel credits pursuant to the provisions of § 80.531, except that for purposes of § 80.531(a), the term "Credit" shall equal V_{15}, without further adjustment.

(c) A refiner that has been approved by EPA as a motor vehicle diesel fuel small refiner under § 80.551(g) may apply for an extension of the duration of its small refiner gasoline sulfur standards pursuant to § 80.553.

* * * * *

(e) The provisions of this section shall apply separately for each refinery owned or operated by a motor vehicle diesel fuel small refiner.

■ 32. Section 80.553 is amended by revising paragraphs (d), (e), (f), and (k) to read as follows:

§ 80.553 Under what conditions may the small refiner gasoline sulfur standards be extended for a small refiner of motor vehicle diesel fuel?

* * * * *

(d) Beginning June 1, 2006, and continuing through December 31, 2010, all motor vehicle diesel fuel produced by a refiner that has received an extension of its small refiner gasoline sulfur standards under this section must be accurately designated under § 80.598 as meeting the 15 ppm sulfur content standard under § 80.520(a)(1).

(e) The total volume of motor vehicle diesel fuel produced for use in the United States and designated as meeting the 15 ppm sulfur content standard under paragraph (d) of this section must meet or exceed 85 percent of the baseline volume established under paragraph (c) of this section, except that for the first compliance period from June 1, 2006 through June 30, 2007, the total volume must meet or exceed 92 percent of the baseline volume.

(f) Compliance with the volume requirements in paragraph (e) of this section shall be determined each compliance period. Annual compliance periods shall be from July 1 through June 30. For the year 2006, the compliance period shall be from June 1, 2006 through June 30, 2007 and for the year 2009 the compliance period shall be from July 1, 2009 through May 31, 2010.

* * * * *

(k) A refiner may petition the Administrator to vacate an extension of the small refiner gasoline sulfur content standards. EPA may grant such a petition, effective July 1 of the compliance period following receipt of such petition (or effective June 1, 2006, if applicable). Upon such effective date, all gasoline produced by the refiner must meet the gasoline sulfur content standards under subpart H of this part as if there had been no extension of the small refiner gasoline sulfur content standards under this section. Upon such effective date, the refiner shall not be subject to the requirements of this section.

* * * * *

■ 33. A new § 80.554 is added to read as follows:

§ 80.554 What compliance options are available to NRLM diesel fuel small refiners?

(a) *Option 1:* A refiner that has been approved by EPA as a NRLM diesel fuel small refiner under § 80.551(g) may produce NRLM diesel fuel from crude oil from June 1, 2007 through May 31, 2010, that is exempt from the standards under § 80.510(a), but only for a refinery located outside the areas specified under § 80.510(g)(1).

(1) The volume of NRLM diesel fuel that is exempt from § 80.510(a) must be less than or equal to 105 percent of B_{NRLM} as defined under § 80.533, less any volume of heating oil produced.

(2) Any volume of NRLM diesel fuel in excess of the volume allowed under (a)(1) of this section will be subject to the 500 ppm sulfur standard under § 80.510(a).

(3) High-sulfur NRLM produced under this paragraph must—

(i) Be dyed red pursuant to the provisions of § 80.520 at the point of production or importation;

(ii) Be associated with a product transfer document that bears a unique product code as specified under § 80.590; and

(iii) Not be delivered into areas specified under § 80.510(g)(1).

(4) From June 1, 2007 through May 31, 2010, a refiner that has been approved by EPA as a NRLM diesel fuel small refiner under § 80.551(g) may produce at a refinery located in 80.510(g)(2) NRLM diesel fuel that is exempt from the standards under § 80.510(a) only if the refiner first obtains approval from the Administrator for a compliance plan. The compliance plan must detail how the refiner will segregate any fuel produced that does

not meet the standards under § 80.510(a) from the refinery through to the ultimate consumer from fuel having any other designations and from fuel produced by any other refiner. The compliance plan must also identify all ultimate consumers to whom the refiner supplies the fuel that does not meet the standards under § 80.510(a).

(b) *Option 2:* A refiner that has been approved by EPA as a NRLM diesel fuel small refiner under § 80.551(g) may produce NR diesel fuel from crude oil from June 1, 2010, through May 31, 2014, and NRLM diesel fuel from crude oil from June 1, 2012 through May 31, 2014 that is subject to the standards under § 80.510(a), but only for a refinery located outside the areas specified under § 80.510(g)(1).

(1) The volume of NR diesel fuel that may be subject to the 500 ppm sulfur standard from June 1, 2010 through June 30, 2011 must be less than or equal to 113 percent of B_{NRLM}, and from July 1, 2011 through May 31, 2012 must be less than or equal to 96 percent of B_{NRLM}, as defined under § 80.533, less any volume of locomotive and marine diesel fuel produced.

(2) The volume of NRLM diesel fuel that may be subject to the 500 ppm sulfur standard from June 1, 2012 through June 30, 2013 must be less than or equal to 113 percent of B_{NRLM}, and from July 1, 2013 through May 31, 2014 must be less than or equal to 96 percent of B_{NRLM}, as defined under § 80.533.

(3) NRLM diesel fuel produced in excess of the volume allowed under paragraph (b)(1) of this section will be subject to the standards under § 80.510(b) and (c).

(4) 500 ppm sulfur NRLM diesel fuel produced under this paragraph must—

(i) Bear a unique product code as specified under § 80.590; and

(ii) Not be sold or delivered into areas specified under § 80.510(g)(1).

(5) From June 1, 2010 through May 31, 2012, for NR diesel fuel, and from June 1, 2012 through May 31, 2014 for NRLM diesel fuel, a refiner that has been approved by EPA as a NRLM diesel fuel small refiner under § 80.551(g) may produce, at a refinery located in Alaska, NR and NRLM diesel fuel, as applicable, from crude oil that is subject to the standards of § 80.510(a), only if the refiner first obtains approval from the Administrator for a compliance plan. The compliance plan must detail how the refiner will segregate any fuel produced subject to the standards under § 80.510(a) from the refinery through to the ultimate consumer from fuel having any other designations and from fuel produced by any other refiner. The compliance plan must also identify all ultimate consumers to whom the refiner supplies the fuel that does not meet the standards under § 80.510(a).

(c) *Option 3:* A refiner that has been approved by EPA as a NRLM diesel fuel small refiner under § 80.551(g) may generate diesel fuel credits under the provisions of § 80.535(b) and (d), except as provided in paragraph (d)(1) of this section.

(d) *Option 4:* (1) In lieu of Options 1, 2, and 3 of this section, a refiner that has been approved by EPA as a NRLM diesel fuel small refiner under § 80.551(g) may choose to adjust its small refiner gasoline sulfur standards, subject to the following conditions:

(i) From June 1, 2006 until the expiration of the refiner's small refiner gasoline sulfur standards (through December 31, 2007 or 2010) 95 percent of the NRLM diesel fuel produced by the refiner must be accurately designated under § 80.598(a) as meeting the 15 ppm sulfur standard of § 80.510(b).

(ii) The refiner must produce NRLM diesel fuel each year or partial year under paragraph (d)(1)(i) of this section at a volume that is equal to or greater than 85 percent of B_{NRLM}, as defined in § 80.533, calculated on an annual basis.

(2)(i) For a refiner meeting the conditions of paragraph (d)(1) of this section, beginning January 1, 2004, the applicable small refiner's annual average and per-gallon cap gasoline sulfur standards will be the standards of § 80.240(a) increased by a factor of 1.20 for the duration of the refiner's small refiner gasoline sulfur standards under § 80.240(a) or § 80.553 (*i.e.*, through calendar years 2007 or 2010).

(ii) In no case may the per-gallon cap exceed 450 ppm.

(3)(i) If the refiner fails to produce the necessary volume of 15 ppm sulfur NRLM diesel fuel by June 1, 2006 and every year thereafter through the deadlines specified under paragraph (d)(1)(i) of this section, the refiner must report this in its annual report under § 80.604, and the adjustment of gasoline sulfur standards under paragraph (d)(2)(i) of this section will be considered void as of January 1, 2004.

(ii) If such a refiner had produced gasoline above its interim gasoline sulfur standard of § 80.240(a) prior to June 1, 2006, such fuel will not be considered in violation of the small refiner standards under § 80.240(a), provided the refiner obtains and uses a quantity of gasoline sulfur credits equal to the volume of gasoline exceeding the small refiner standards multiplied by the number of parts per million by which the gasoline exceeded the small refiner standards.

(e) *Multiple refineries.* The provisions of this section shall apply separately for each refinery owned or operated by a NRLM diesel fuel small refiner.

(f) *Other provisions.* From June 1, 2007 through May 31, 2010, a refiner who is an approved motor vehicle diesel fuel small refiner under § 80.550(a) but does not qualify as a NRLM diesel fuel small refiner under § 80.550(b) may produce NRLM diesel fuel that is exempt from the per-gallon sulfur standard and the cetane or aromatics standard of § 80.510(a). This exemption does not apply to diesel fuel sold or intended for sale in the areas listed in § 80.510(g)(1) or (g)(2). From June 1, 2010 through May 31, 2012, NR and LM diesel fuel produced by such refiners is subject to the standards under § 80.510(b) and beginning June 1, 2012, all NRLM diesel fuel is subject to the standards under § 80.510(c).

■ 34. A new § 80.555 is added to read as follows:

§ 80.555 What provisions are available to a large refiner that acquires a small refiner or one or more of its refineries?

(a) In the case of a refiner without approved small refiner status who acquires a refinery from a refiner with approved status as a motor vehicle diesel fuel small refiner or a NRLM diesel fuel small refiner under § 80.551(g), the applicable small refiner provisions of §§ 80.552 and 80.554 may apply to the acquired refinery for a period of up to 30 months from the date of acquisition of the refinery. In no case shall this period extend beyond May 31, 2010 for a refinery acquired from a motor vehicle diesel fuel small refiner or beyond the dates specified in § 80.554(a) or (b), as applicable, for a refinery acquired from a NRLM diesel fuel small refiner.

(b) A refiner may apply to EPA for up to an additional six months to comply with the standards of § 80.510 or 80.520 for the acquired refinery if more than 30 months would be required for the necessary engineering, permitting, construction, and start-up work to be completed. Such applications must include detailed technical information supporting the need for additional time. EPA will base a decision to approve additional time on information provided by the refiner and on other relevant information. In no case will EPA extend the compliance date beyond May 31, 2010 for a refinery acquired from a motor vehicle diesel fuel small refiner or beyond the dates specified in § 80.554(a) or (b), as applicable, for a refinery acquired from a NRLM diesel fuel small refiner.

(c) Refiners who acquire a refinery from a refiner with approved status as a motor vehicle diesel fuel small refiner or a NRLM diesel fuel small refiner under § 80.551(g), shall notify EPA in writing no later than 20 days following the acquisition.

■ 35. Section 80.560 is amended by revising paragraphs (a), (b), (d), (e), (h), (i), (k), and (l) to read as follows:

§ 80.560 How can a refiner seek temporary relief from the requirements of this subpart in case of extreme hardship circumstances?

(a) EPA may, at its discretion, grant a refiner of crude oil that processes crude oil through refinery processing units, for one or more of its refineries, temporary relief from some or all of the provisions of this subpart. Such relief shall be no less stringent than the small refiner compliance options specified in § 80.552 for motor vehicle diesel fuel and § 80.554 for NRLM diesel fuel. EPA may grant such relief provided that the refiner demonstrates that—

(1) Unusual circumstances exist that impose extreme hardship and significantly affect the refiner's ability to comply by the applicable date; and

(2) It has made best efforts to comply with the requirements of this subpart.

(b)(1) For motor vehicle diesel fuel, applications must be submitted to EPA by June 1, 2002 to the following address: U.S. EPA—Attn: Diesel Hardship, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460 (certified mail/return receipt) or Attn: Diesel Hardship, Transportation and Regional Programs Division, 1310 L Street, NW., 6th floor, Washington, DC 20005 (express mail/return receipt). EPA reserves the right to deny applications for appropriate reasons, including unacceptable environmental impact. Approval to distribute motor vehicle diesel fuel not subject to the 15 ppm sulfur standard may be granted for such time period as EPA determines is appropriate, but shall not extend beyond May 31, 2010.

(2) For NRLM diesel fuel, applications must be submitted to EPA by June 1, 2005 to the following address: U.S. EPA—Attn: Diesel Hardship, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460 (certified mail/return receipt) or Attn: Diesel Hardship, Transportation and Regional Programs Division, 1310 L Street, NW., 6th floor, Washington, DC 20005 (express mail/return receipt). EPA reserves the right to deny applications for appropriate reasons, including unacceptable environmental impact. Approval to distribute NRLM diesel fuel not subject to the 500 ppm sulfur standard may be granted for such time period as EPA determines is appropriate, but shall not extend beyond May 31, 2010 for NR diesel fuel and May 31, 2012 for NRLM diesel fuel. Approval to distribute NRLM diesel fuel not subject to the 15 ppm sulfur standard may be granted for such time period as EPA determines is appropriate, but shall not extend beyond May 31, 2014.

* * * * *

(d) Applicants must provide, at a minimum, the following information:

(1) Detailed description of efforts to obtain capital for refinery investments and efforts made to obtain credits for compliance under § 80.531 for motor vehicle diesel fuel or §§ 80.535 through 80.536 for NRLM diesel fuel;

(2) Bond rating of entity that owns the refinery (in the case of joint ventures, include the bond rating of the joint venture entity and the bond ratings of all partners; in the case of corporations, include the bond ratings of any parent or subsidiary corporations); and

(3) Estimated capital investment needed to comply with the requirements of this subpart by the applicable date.

(e) In addition to the application requirements of paragraph (b) through (d) of this section, a refiner's application for temporary relief under this paragraph (e) must also include a compliance plan. Such compliance plan shall demonstrate how the refiner will engage in a quality assurance testing program, where appropriate, to ensure that the following conditions are met:

(1)(i) Its motor vehicle diesel fuel subject solely to the sulfur standards under § 80.520(c) has not caused motor vehicle diesel fuel subject to the 15 ppm sulfur standard § 80.520(a)(1) to fail to comply with that standard; or

(ii) Its NRLM diesel fuel subject solely to the 500 ppm sulfur standard under § 80.510(a) has not caused NRLM diesel fuel subject to the 15 ppm sulfur standard under § 80.510(b) or (c) to fail to comply with that standard.

(2) The quality assurance program must at least include periodic sampling and testing at the party's own facilities and at downstream facilities in the refiner's or importer's diesel fuel distribution system, to determine compliance with the applicable sulfur standards for both categories of motor vehicle diesel fuel; examination at the party's own facilities and at applicable downstream facilities, of product transfer documents to confirm appropriate transfers and deliveries of both products; and inspection of retailer and wholesale purchaser-consumer pump stands for the presence of the labels and warning signs required under this section. Any violations that are discovered shall be reported to EPA within 48 hours of discovery.

* * * * *

(h) Refiners who are granted a hardship relief standard for any refinery and importers of fuel subject to temporary foreign refiner relief standards, must comply with the requirements of § 80.561(f).

(i) EPA may impose any reasonable conditions on waivers under this section, including limitations on the refinery's volume of motor vehicle diesel fuel and NRLM diesel fuel subject to temporary refiner relief standards.

* * * * *

(k) The individual refinery sulfur standard and the compliance plan will be approved or disapproved by the Administrator, and approval will be effective when the refiner receives an approval letter from EPA. Unless approved, the refiner or, where applicable, the importer must comply with the motor vehicle diesel fuel standard under § 80.520(a)(1) by the appropriate compliance date specified in § 80.500 or the NRLM diesel fuel standards and compliance dates under § 80.510(a), (b), and (c) as applicable.

(l) If EPA finds that a refiner provided false or inaccurate information on its application for hardship relief, EPA's approval of the refiners application will be void *ab initio*.

■ 36. Section 80.561 is amended by revising the introductory text and paragraphs (c), (d), and (f) to read as follows:

§ 80.561 How can a refiner or importer seek temporary relief from the requirements of this subpart in case of extreme unforseen circumstances?

In appropriate extreme, unusual, and unforseen circumstances (for example, natural disaster or refinery fire) which are clearly outside the control of the refiner or importer and which could not have been avoided by the exercise of prudence, diligence, and due care, EPA may permit a refiner or importer, for a brief period, to distribute motor vehicle diesel fuel or NRLM diesel fuel which does not meet the requirements of this subpart if:

* * * * *

(c) The refiner or importer can show how the requirements for motor vehicle diesel fuel or NRLM diesel fuel will be expeditiously achieved;

(d) The refiner or importer agrees to make up any air quality detriment associated with the nonconforming motor vehicle diesel fuel or NRLM diesel fuel, where practicable;

* * * * *

(f)(1) In the case of motor vehicle diesel fuel distributed under this section that does not meet the 15 ppm sulfur standard under § 80.520(a)(1), such diesel fuel shall not be distributed for use in model year 2007 or later motor vehicles, and must meet all the requirements and prohibitions of this subpart applicable to diesel fuel meeting the sulfur standard under § 80.520(c), or to diesel fuel that is not motor vehicle diesel fuel, as applicable.

(2) In the case of NRLM diesel fuel distributed under this section from June 1, 2007 through May 31, 2010 that does not meet the 500 ppm sulfur standard under § 80.510(a), such diesel fuel must meet the requirements and prohibitions applicable to high sulfur NRLM credit fuel under § 80.536(f)(1)(i) and (ii).

(3) In the case of NR diesel fuel distributed under this section after May 31, 2010 that does not meet the 15 ppm sulfur standard under § 80.510(b), such diesel fuel shall not be distributed for use in model year 2011 or later nonroad engines, and must meet all the requirements and prohibitions of this subpart applicable to diesel fuel meeting the sulfur standard under § 80.510(a) for NRLM diesel fuel.

(4) In the case of NRLM diesel fuel distributed under this section after May 31, 2012 that does not meet the 15 ppm sulfur standard under § 80.510(c), such diesel fuel shall not be distributed for use in model year 2011 or later nonroad engines, and must meet all the requirements and prohibitions of this subpart applicable to diesel fuel meeting the sulfur standard under § 80.510(a) for NRLM diesel fuel.

■ 37. Section 80.570 is revised to read as follows:

§ 80.570 What labeling requirements apply to retailers and wholesale purchaser-consumers of diesel fuel beginning June 1, 2006?

(a) From June 1, 2006 through May 31, 2010, any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing, motor vehicle diesel fuel subject to the 15 ppm sulfur standard of § 80.520(a)(1), must affix the following conspicuous and legible label, in block letters of no less than 24-point bold type, and printed in a color contrasting with the background, to each pump stand:

ULTRA-LOW SULFUR HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all model year 2007 and later highway diesel vehicles and engines.

Recommended for use in all diesel vehicles and engines.

(b) From June 1, 2006 through September 30, 2010, any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing, motor vehicle diesel fuel subject to the 500 ppm sulfur standard of § 80.520(c), must prominently and conspicuously display in the immediate area of each pump stand from which motor vehicle fuel subject to the 500 ppm sulfur standard is offered for sale or dispensing, the following legible label, in block letters of no less than 24-point bold type, printed in a color contrasting with the background:

LOW SULFUR HIGHWAY DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in model year 2007 and later highway vehicles and engines.

Its use may damage these vehicles and engines.

(c) From June 1, 2006 through May 31, 2007, any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing, diesel fuel for non-motor vehicle equipment that does not meet the standards for motor vehicle diesel fuel, must affix the following conspicuous and legible label, in block letters of no less than 24-point bold type, and printed in a color contrasting with the background, to each pump stand:

NON-HIGHWAY DIESEL FUEL (May Exceed 500 ppm Sulfur)

WARNING

Federal law *prohibits* use in highway vehicles or engines.

Its use may damage these vehicles and engines.

(d) The labels required by paragraphs (a) through (c) of this section must be placed on the vertical surface of each pump housing and on each side that has gallon and price meters. The labels shall be on the upper two-thirds of the pump, in a location where they are clearly visible.

(e) Alternative labels to those specified in paragraphs (a) through (c) of this section may be used as approved by the Administrator.

■ 38. A new § 80.571 is added to read as follows:

§ 80.571 What labeling requirements apply to retailers and wholesale purchaser-consumers of NRLM diesel fuel or heating oil beginning June 1, 2007?

Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing nonroad, locomotive or marine (NRLM) diesel fuel (including nonroad (NR) and locomotive or marine (LM)), or heating oil, must prominently and conspicuously display in the immediate area of each pump stand from which non-highway diesel fuel is offered for sale or dispensing, one of the following legible labels, as applicable, in block letters of no less than 24-point bold type, printed in a color contrasting with the background:

(a) From June 1, 2007 through May 31, 2010, for pumps dispensing NRLM diesel fuel meeting the 15 ppm sulfur standard of § 80.510(b):

ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all model year 2011 and newer nonroad diesel engines.

Recommended for use in all nonroad, locomotive, and marine diesel engines.

WARNING

Federal Law *prohibits* use in highway vehicles or engines.

(b) From June 1, 2007 through May 31, 2010, for pumps dispensing NRLM diesel fuel meeting the 500 ppm sulfur standard of § 80.510(a):

LOW SULFUR NON-HIGHWAY DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal Law *prohibits* use in highway vehicles or engines.

(c) From June 1, 2007 through September 30, 2010, for pumps dispensing NRLM diesel fuel not meeting, or not offered as meeting, the 500 ppm sulfur standard of § 80.510(a) or the 15 ppm sulfur standard of § 80.510(b):

HIGH SULFUR NON-HIGHWAY DIESEL FUEL (May Exceed 500 ppm Sulfur)

WARNING

Federal law *prohibits* use in highway vehicles or engines.

May damage nonroad diesel engines required to use low-sulfur or ultra-low sulfur diesel fuel.

(d) From June 1, 2007 and beyond, for pumps dispensing non-motor vehicle diesel fuel for use other than in nonroad, locomotive or marine engines, such as for use in stationary diesel engines or as heating oil:

HEATING OIL (May Exceed 500 ppm Sulfur)

WARNING

Federal law *prohibits* use in highway vehicles or engines, or in nonroad, locomotive, or marine diesel engines.

Its use may damage these diesel engines.

(e) The labels required by paragraphs (a) through (d) of this section must be placed on the vertical surface of each pump housing and on each side that has gallon and price meters. The labels shall be on the upper two-thirds of the pump, in a location where they are clearly visible.

(f) Alternative labels to those specified in paragraphs (a) through (d) of this section may be used as approved by the Administrator.

■ 39. A new § 80.572 is added to read as follows:

§ 80.572 What labeling requirements apply to retailers and wholesale purchaser-consumers of NR and NRLM diesel fuel and heating oil beginning June 1, 2010?

Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing nonroad, locomotive or marine (NRLM) diesel fuel (including nonroad (NR) and locomotive or marine (LM)), or heating oil, must prominently and conspicuously display in the immediate area of each pump stand from which non-highway diesel fuel is offered for sale or dispensing, one of the following legible labels, as applicable, in block letters of no less than 24-point bold type, printed in a color contrasting with the background:

(a) From June 1, 2010 and beyond, any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing, motor vehicle diesel fuel subject to the 15 ppm sulfur standard of § 80.520(a)(1), must affix the following conspicuous and legible label, in block letters of no less than 24-point bold type, and printed in a color contrasting with the background, to each pump stand:

ULTRA-LOW SULFUR HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all highway diesel vehicles and engines.

Recommended for use in all diesel vehicles and engines.

(b) From June 1, 2010 through May 31, 2012, for pumps dispensing NR diesel fuel subject to the 15 ppm sulfur standard of § 80.510(b):

ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all model year 2011 and later nonroad diesel engines.

Recommended for use in all other non-highway diesel engines.

WARNING

Federal law *prohibits* use in highway vehicles or engines.

(c) From June 1, 2010 through September 30, 2014, for pumps dispensing NRLM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a):

LOW SULFUR NON-HIGHWAY DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in all model year 2011 and newer nonroad engines.

May damage model year 2011 and newer nonroad engines.

Federal law *prohibits* use in highway vehicles or engines.

(d) From June 1, 2010 through September 30, 2012, for pumps dispensing LM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a):

LOW SULFUR LOCOMOTIVE AND MARINE DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in nonroad engines or in highway vehicles or engines.

(e) The labels required by paragraphs (a) through (d) of this section must be placed on the vertical surface of each pump housing and on each side that has gallon and price meters. The labels shall be on the upper two-thirds of the pump, in a location where they are clearly visible.

(f) Alternative labels to those specified in paragraphs (a) through (d) of this section may be used as approved by the Administrator.

■ 40. A new § 80.573 is added to read as follows:

§ 80.573 What labeling requirements apply to retailers and wholesale purchaser-consumers of NRLM diesel fuel and heating oil beginning June 1, 2012?

Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing nonroad, locomotive or marine (NRLM) diesel fuel (including nonroad (NR) and locomotive or marine (LM)), or heating oil, must prominently and conspicuously display in the immediate area of each pump stand from which non-highway diesel fuel is offered for sale or dispensing, one of the following legible labels, as applicable, in block letters of no less than 24-point bold type, printed in a color contrasting with the background:

(a) From June 1, 2012 through May 31, 2014, for pumps dispensing NRLM diesel fuel subject to the 15 ppm sulfur standard of § 80.510(c):

ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all model year 2011 and later nonroad diesel engines.

Recommended for use in all other non-highway diesel engines.

WARNING

Federal law *prohibits* use in highway vehicles or engines.

(b) The labels required by paragraph (a) of this section must be placed on the vertical surface of each pump housing and on each side that has gallon and price meters. The labels shall be on the upper two-thirds of the pump, in a location where they are clearly visible.

(c) Alternative labels to those specified in paragraph (a) of this section may be used as approved by the Administrator.

■ 41. A new § 80.574 is added to read as follows:

§ 80.574 What labeling requirements apply to retailers and wholesale purchaser-consumers of NRLM diesel fuel, or heating oil beginning June 1, 2014?

Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing nonroad, locomotive or marine (NRLM) diesel fuel (including nonroad (NR) and locomotive or marine (LM)), or heating oil, must prominently and conspicuously display in the immediate area of each pump stand from which non-highway diesel fuel is offered for sale or dispensing, one of the following legible labels, as applicable, in block letters of no less than 24-point bold type, printed in a color contrasting with the background:

(a) From June 1, 2014 and beyond, for pumps dispensing NRLM diesel fuel subject to the 15 ppm sulfur standard of § 80.510(c):

ULTRA-LOW SULFUR NON-HIGHWAY DIESEL FUEL (15 ppm Sulfur Maximum)

Required for use in all nonroad diesel engines.

Recommended for use in all locomotive and marine diesel engines.

WARNING

Federal law *prohibits* use in highway vehicles or engines.

(b) From June 1, 2014 and beyond, for pumps dispensing LM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a):

LOW SULFUR LOCOMOTIVE OR MARINE DIESEL FUEL (500 ppm Sulfur Maximum)

WARNING

Federal law *prohibits* use in nonroad engines or in highway vehicles or engines.

Its use may damage these engines.

(c) The labels required by paragraphs (a) and (b) of this section must be placed on the vertical surface of each pump housing and on each side that has gallon and price meters. The labels shall be on the upper two-thirds of the pump, in a location where they are clearly visible.

(d) Alternative labels to those specified in paragraphs (a) and (b) of this section may be used as approved by the Administrator.

■ 42. Section 80.580 is revised to read as follows:

§ 80.580 What are the sampling and testing methods for sulfur?

The sulfur content of diesel fuel and diesel fuel additives is to be determined in accordance with this section.

(a) *Sampling method.* The applicable sampling methodology is provided in § 80.330(b).

(b) *Test method for sulfur.* (1) Until December 27, 2004, for motor vehicle diesel fuel and diesel fuel additives subject to the 15 ppm sulfur standard of § 80.520(a)(1), sulfur content may be determined using ASTM D 6428–99.

(2) For motor vehicle diesel fuel and diesel fuel additives subject to the 500 ppm sulfur standard of § 80.520(c), and NRLM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a)(1), sulfur content may be determined using ASTM D 2622–03.

(3) Beginning August 30, 2004, for motor vehicle diesel fuel and diesel fuel additives subject to the 15 ppm sulfur standard of § 80.520(a)(1), sulfur content may be determined using any test method approved under § 80.585.

(4) Beginning August 30, 2004, for NRLM diesel fuel and diesel fuel additives subject to the 15 ppm standard of § 80.510(b), sulfur content may be determined using any test method approved under § 80.585.

(c) *Alternative test methods for sulfur.* (1) Until December 27, 2004, for motor vehicle diesel fuel and diesel fuel additives subject to the 15 ppm standard of § 80.520(a)(1), sulfur content may be determined using ASTM D 5453–03a or ASTM D 3120–03a, provided that the refiner or importer test result is correlated with the appropriate method specified in paragraph (a)(2) of this section.

(2) *Options for testing sulfur content of 500 ppm diesel fuel.* (i) For motor vehicle diesel fuel and diesel fuel additives subject to the 500 ppm sulfur standard of § 80.520(c), and for NRLM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a), sulfur content may be determined using ASTM D 4294–03, ASTM D 5453–03a, or ASTM D 6428–99, provided that the refiner or importer test result is correlated with the appropriate method specified in paragraph (a)(2)(ii) of this section; or

(ii) For motor vehicle diesel fuel and diesel fuel additives subject to the 500 ppm sulfur standard of § 80.520(c), and for NRLM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a), sulfur content may be determined using any test method approved under § 80.585.

(d) *Adjustment Factor for downstream test results.* An adjustment factor of negative two ppm sulfur shall be applied to the test results, to account for test variability, but only for testing of motor vehicle diesel fuel or NRLM diesel fuel identified as subject to the 15 ppm sulfur standard of § 80.510(b) or § 80.520(a)(1).

(e) *Materials incorporated by reference.* The Director of the Federal Register approved the incorporation by reference of the documents listed in this section as prescribed in 5 U.S.C. 552(a) and 1 CFR part 51. Anyone may inspect copies at the U.S. EPA, Air and Radiation Docket and Information Center, 1301 Constitution Ave., NW., Room B102, EPA West Building, Washington, DC 20460 or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(1) *ASTM material.* Anyone may purchase copies of these materials from the American Society for Testing and Materials, 100 Barr Harbor Dr., West Conshohocken, PA 19428.

(i) ASTM D 2622–03, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry.

(ii) ASTM D 3120–03a, Standard Test Method for Trace Quantities of Sulfur in Light Liquid Petroleum Hydrocarbons by Oxidative Microcoulometry.

(iii) ASTM D 4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-ray Fluorescence Spectrometry.

(iv) ASTM D 5453–03a, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Motor Oils by Ultraviolet Fluorescence.

(v) ASTM D 6428–99, Test Method for Total Sulfur in Liquid Aromatic Hydrocarbons and Their Derivatives by Oxidative Combustion and Electrochemical Detection.

(2) [Reserved]

■ 43. A new § 80.581 is added to read as follows:

§ 80.581 What are the batch testing and sample retention requirements for motor vehicle and NRLM diesel fuel?

(a) Beginning on June 1, 2006 or earlier pursuant to § 80.531 for motor vehicle diesel fuel, and beginning June 1, 2010 or earlier pursuant to § 80.535 for NRLM diesel fuel, each refiner and importer shall collect a representative sample from each batch of motor vehicle or NRLM diesel fuel produced or imported and subject to the 15 ppm sulfur content standard. Batch, for the purposes of this section, means batch as defined under § 80.2 but without the reference to transfer of custody from one facility to another facility.

(b) Except as provided in paragraph (c) of this section, the refiner or importer shall test each sample collected pursuant to paragraph (a) of this section to determine its sulfur content for compliance with the requirements of this subpart prior to the diesel fuel leaving the refinery or import facility, using an appropriate sampling and testing method as specified in § 80.580.

(c)(1) Any refiner who produces motor vehicle or NRLM diesel fuel using computer-controlled in-line blending equipment, including the use of an on-line analyzer test method that is approved under the provisions of § 80.580, and who, subsequent to production of the diesel fuel batch tests a composited sample of the batch under the provisions of § 80.580 for purposes of designation and reporting, is exempt from the requirement of paragraph (b) of this section to obtain the test result required under this section prior to the diesel fuel leaving the refinery, provided that the refiner obtains approval from EPA.

(2) To obtain an exemption from paragraph (b) of this section, the refiner must submit to EPA all the information required under § 80.65(f)(4)(i)(A). A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the submission is true to the best of his/her belief must accompany any submission under this paragraph (c)(2).

(3) Refiners who seek an exemption under paragraph (c)(2) of this section must comply with any request by EPA for additional information or any other requirements that EPA includes as part of the exemption.

(4) Within 60 days of EPA's receipt of a submission under paragraph (c)(2) of this section, EPA will notify the refiner if the exemption is not approved or of any deficiencies in the refiner's submission, or if any additional information is required or other requirements are included in the exemption pursuant to paragraph (c)(3) of this section. In the absence of such notification from EPA, the effective date of an exemption under this paragraph (c) is 60 days from EPA's receipt of the refiner's submission.

(5) EPA reserves the right to modify the requirements of an exemption under

this paragraph (c), in whole or in part, at any time, if EPA determines that the refiner's operation does not effectively or adequately control, monitor or document the sulfur content of the refinery's diesel fuel production, or if EPA determines that any other circumstances exist which merit modification of the requirements of an exemption, such as advancements in the state of the art for in-line blending measurement which allow for additional control or more accurate monitoring or documentation of sulfur content. If EPA finds that a refiner provided false or inaccurate information in any submission required for an exemption under this section, upon notification from EPA, the refiner's exemption will be void *ab initio*.

(d) All test results under this section shall be retained for five years and must be provided to EPA upon request.

(e) Samples collected under this section must be retained for at least 30 days and provided to EPA upon request.

■ 44. A new § 80.582 is added to read as follows:

§ 80.582 What are the sampling and testing methods for the fuel marker?

For heating oil and NRLM diesel fuel subject to the fuel marker requirement in § 80.510(d), (e), or (f), the identification of the presence and concentration of the fuel marker in diesel fuel may be determined using the test procedures qualified in accordance with the requirements in this section.

(a) *Sampling and testing for methods for the fuel marker.* The sampling, sample preparation, and testing methods qualified for use in accordance with the requirements of this section may involve the use of hazardous materials, operations and equipment. This section does not address the associated safety problems which may exist. It is the responsibility of the user of the procedures specified in this section to establish appropriate safety and health practices prior to their use. It is also the responsibility of the user to dispose of any byproducts which might result from conducting these procedures in a manner consistent with applicable safety and health requirements.

(b) *What are the precision and accuracy criteria for qualification of fuel marker test methods?* (1) *Precision.* A standard deviation of less than 0.10 milligrams per liter is required, computed from the results of a minimum of 20 repeat tests made over 20 days on samples taken from a homogeneous commercially available diesel fuel which meets the applicable industry consensus and federal regulatory specifications and which contains the fuel marker at a concentration in the range of 0.10 to 8 milligrams per liter. In order to qualify, the 20 results must be a series of tests on the same material and there must be a sequential record of the analysis with no omissions. A laboratory facility may exclude a given sample or test result only if the exclusion is for a valid reason under good laboratory practices and it maintains records regarding the sample and test results and the reason for excluding them.

(2) *Accuracy.* (i) The arithmetic average of a continuous series of at least 10 tests performed on a commercially available marker solvent yellow 124 standard in the range of 0.10 to 1 milligrams per liter shall not differ from the ARV of that standard by more than 0.05 milligrams per liter.

(ii) The arithmetic average of a continuous series of at least 10 tests performed on a commercially available marker solvent yellow 124 standard in the range of 4 to 10 milligrams per liter shall not differ from the ARV of that standard by more than 0.05 milligrams per liter.

(iii) In applying the tests of paragraphs (b)(2)(i) and (ii) of this section, individual test results shall be compensated for any known chemical interferences.

(c) *What process must a test facility follow in order to qualify a test method for determining the fuel marker content of distillate fuels and how will EPA qualify or decline to qualify a test method?* (1) *Qualification of test methods approved by voluntary consensus-based standards bodies.* Any standard test method developed by a Voluntary Consensus-Based Standards Body, such as the American Society for Testing and Materials (ASTM) or International Standards Organization (ISO), shall be considered a qualified test method for determining the fuel marker content of distillate fuel provided that it meets the precision and accuracy criteria under paragraph (b) of this section. The qualification of a test method is limited to the single test facility that performed the testing for accuracy and precision. The individual facility must submit the accuracy and precision results for each method, including information on the date and time of each test measurement used to demonstrate precision, following procedures established by the Administrator.

(2) *Qualification of test methods that have not been approved by a voluntary consensus-based standards body.* A test method that has not been approved by a voluntary consensus-based standards body may be qualified upon approval by the Administrator. The following information must be submitted in the application for approval by each test facility, for each test method that it wishes to have approved:

(i) Full test method documentation, including a description of the technology and/or instrumentation that makes the method functional.

(ii) Information demonstrating that the test method meets the accuracy and precision criteria under paragraph (b) of this section, including information on the date and time of each test measurement used to demonstrate precision.

(iii) Samples used for precision and accuracy determination must be retained for 90 days.

(iv) If requested by the Administrator, test results utilizing the method and performed on a sample of commercially available distillate fuel which meets the applicable industry consensus and federal regulatory specifications and which contains the fuel marker.

(v) Any additional information requested by the Administrator and necessary to render a decision as to qualification of the test method.

(vi) The qualification of a test method is limited to the single test facility that performed the testing for accuracy and precision and any other required testing.

(3)(i) Within 90 days of receipt of all materials required to be submitted under paragraph (c)(1) or (c)(2) of this section, the Administrator shall determine whether to qualify the test method under this section. The Administrator shall qualify the test method if all materials required under this section are received and the test method meets the accuracy and precision criteria of paragraph (b) of this section.

(ii) If the Administrator denies approval of the test method, within 90 days of receipt of all materials required to be submitted under this section, the Administrator will notify the applicant of the reasons for not approving the method. If the Administrator does not notify the applicant within 90 days of receipt of the application, that the test method is not approved, then the test method shall be deemed approved.

(iii) If the Administrator finds that an individual test facility has provided false or inaccurate information under this section, upon notice from the Administrator, the qualification shall be void *ab initio*.

(iv) The qualification of any test method under this paragraph (c) shall be valid for the duration of the period during which the fuel marker requirements remain applicable under this subpart.

(d) *Quality control procedures for fuel marker measurement instrumentation.* A test shall not be considered a test using a qualified test method unless the following quality control procedures are performed separately for each instrument used to make measurements:

(1) Follow all mandatory provisions of ASTM D 6299–02 and construct control charts from the mandatory quality control testing prescribed in paragraph 7.1 of the reference method, following guidelines under A 1.5.1 for individual observation charts and A 1.5.2 for moving range charts. The Director of the Federal Register approved the incorporation by reference of ASTM D 6299–02, Standard Practice for Applying Statistical Quality Assurance Techniques to Evaluate Analytical Measurement System Performance, as prescribed in 5 U.S.C. 552(a) and 1 CFR part 51. Anyone may purchase copies of this standard from the American Society for Testing and Materials, 100 Barr Harbor Dr., West Conshohocken, PA 19428. Anyone may inspect copies at the U.S. EPA, Air and Radiation Docket and Information Center, 1301 Constitution Ave., NW., Room B102, EPA West Building, Washington, DC 20460 or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(2) Follow paragraph 7.3.1 of ASTM D 6299–02 to check standards using a reference material at least monthly or following any major change to the laboratory equipment or test procedure. Any deviation from the accepted reference value of a check standard greater than 0.10 milligrams per liter must be investigated.

(3) Samples of tested batches must be retained for 30 days or the period equal to the interval between quality control sample tests, whichever is longer.

(4) Upon discovery of any quality control testing violation of paragraph A 1.5.1.3 or A 1.5.2.1 of ASTM D 6299–02, or any check standard deviation greater than 0.10 milligrams per liter, conduct an investigation into the cause of such violation or deviation and, after restoring method performance to statistical control, retest retained samples from batches originally tested since the last satisfactory quality control material or check standard testing occasion.

(5) Retain results of quality control testing and retesting of retained samples under paragraph (d)(3) of this section for five years.

■ 45. A new § 80.583 is added to read as follows:

§ 80.583 What alternative sampling and testing requirements apply to importers who transport motor vehicle diesel fuel or NRLM diesel fuel by truck or rail car?

Importers who import diesel fuel subject to the 15 ppm sulfur standard under § 80.510(b) or (c) or 80.520(a) into the United States by truck or by rail car may comply with the following requirements instead of the requirements to sample and test each batch of fuel designated as subject to the 15 ppm sulfur standard under § 80.581 otherwise applicable to importers:

(a) *Terminal testing.* For purposes of determining compliance with the 15 ppm sulfur standard, the importer may use test results for sulfur content testing conducted by the foreign truck-loading or rail car-loading terminal operator for diesel fuel contained in the storage tank from which trucks or rail cars used to transport diesel fuel designated as subject to the 15 ppm sulfur content standard into the United States are loaded, provided the following conditions are met:

(1) The sampling and testing shall be performed after each receipt of diesel fuel into the storage tank, or immediately before each transfer of diesel fuel to the importer's truck or rail car.

(2) The sampling and testing shall be performed according to § 80.580.

(3) At the time of each transfer of diesel fuel to the importer's truck or rail car for import to the U.S., the importer must obtain a copy of the terminal test result that indicates the sulfur content of the truck or rail car load, or truck or rail car compartment load, as applicable.

(b) *Quality assurance program.* The importer must conduct a quality assurance program, as specified in this paragraph (b), for each truck or rail car loading terminal.

(1) Quality assurance samples must be obtained from the truck-loading or rail car loading terminal and tested by the importer, or by an independent laboratory, and the terminal operator must not know in advance when samples are to be collected.

(2) The sampling and testing must be performed using the methods specified in § 80.580.

(3) The frequency of the quality assurance sampling and testing must be at least one sample for each 50 of an importer's trucks or rail cars that are loaded at a terminal, or one sample per month, whichever is more frequent.

(c) *Party required to conduct quality assurance testing.* The quality assurance program under paragraph (b) of this section shall be conducted by the importer. In the alternative, this testing may be conducted by an independent laboratory that meets the criteria under § 80.65(f)(2)(iii), provided the importer receives copies of all results of tests conducted no later than 21 days after the sample was taken.

(d) *Alternative batch designations.* For purposes of maintaining batch records under §§ 80.592, 80.600, and 80.602, designation of batches under § 80.598, and reporting under §§ 80.593, 80.601, and 80.604:

(1) In lieu of treating each portion of a tank truck compartment delivered to a different facility as a different batch, a truck importer may treat each compartment as a batch, if all the fuel in the compartment is delivered only to retail outlets, wholesale purchaser-consumers or other end users. Where different compartments contain homogeneous product of identical designations, the total volume of those compartments may be treated as a single batch, if the entire volume is delivered only to retail outlets, wholesale purchaser-consumers or other ultimate consumers.

(2) Each portion of a rail car (or rail cars) delivery of a different designation or each delivery to a different facility is considered to be a separate batch.

(e) *EPA inspections of terminals.* EPA inspectors or auditors must be given full and immediate access to the truck or rail car-loading terminal and any laboratory at which samples of diesel fuel collected at the terminal are analyzed, and must be allowed to conduct inspections, review records, collect diesel fuel samples and perform audits. These inspections or audits may be either announced or unannounced.

(f) *Certified DFR-Diesel.* This section does not apply to Certified DFR-Diesel as defined in § 80.620.

(g) *Effect of noncompliance.* If any of the requirements of this section are not met, all motor vehicle diesel fuel and NRLM diesel fuel imported by the truck or rail car importer during the time the requirements are not met is deemed in violation of the 15 ppm sulfur diesel fuel standards in § 80.510(b) or (c) or § 80.520(a), as applicable. Additionally, if any requirement is not met, EPA may notify the importer of the violation, and, if the requirement is not fulfilled within 10 days of notification, the truck importer may not in the future use the sampling and testing provisions in this section in lieu of the provisions in § 80.581.

■ 46. A new § 80.584 is added to read as follows:

§ 80.584 What are the precision and accuracy criteria for approval of test methods for determining the sulfur content of motor vehicle and NRLM diesel fuel?

(a) *Precision.* (1) For motor vehicle diesel fuel and diesel fuel additives subject to the 15 ppm sulfur standard of § 80.520(a)(1) and NRLM diesel fuel and diesel fuel additives subject to the 15 ppm sulfur standard of § 80.510(b) and (c), a standard deviation less than 0.72 ppm, computed from the results of a minimum of 20 repeat tests made over 20 days on samples taken from a single homogeneous commercially available diesel fuel with a sulfur content in the range of 5–15 ppm. The 20 results must be a series of tests with a sequential record of the analyses and no omissions. A laboratory facility may exclude a given sample or test result only if the exclusion is for a valid reason under good laboratory practices and it maintains records regarding the sample and test results and the reason for excluding them.

(2) For motor vehicle diesel fuel subject to the 500 ppm sulfur standard of § 80.520(c), and for NRLM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a), of a standard deviation less than 9.68 ppm, computed from the results of a minimum of 20 repeat tests made over 20 days on samples taken from a single homogeneous commercially available diesel fuel with a sulfur content in the range of 200–500 ppm. The 20 results must be a series of tests with a sequential record of the analyses and no omissions. A laboratory facility may exclude a given sample or test result only if the exclusion is for a valid reason under good laboratory practices and it maintains records regarding the sample and test results and the reason for excluding them.

(b) *Accuracy.* (1) For motor vehicle diesel fuel and diesel fuel additives subject to the 15 ppm sulfur standard of § 80.520(a)(1) and NRLM diesel fuel and diesel fuel additives subject to the 15 ppm sulfur standard of § 80.510(b) and (c):

(i) The arithmetic average of a continuous series of at least 10 tests performed on a commercially available gravimetric sulfur standard in the range of 1–10 ppm sulfur shall not differ from the accepted reference value (ARV) of that standard by more than 0.54 ppm sulfur;

(ii) The arithmetic average of a continuous series of at least 10 tests performed on a commercially available gravimetric sulfur standard in the range of 10–20 ppm sulfur shall not differ from the ARV of that standard by more than 0.54 ppm sulfur; and

(iii) In applying the tests of paragraphs (b)(1)(i) and (ii) of this section, individual test results shall be compensated for any known chemical interferences.

(2) For motor vehicle diesel fuel subject to the 500 ppm sulfur standard of § 80.520(c), and for NRLM diesel fuel subject to the 500 ppm sulfur standard of § 80.510(a):

(i) The arithmetic average of a continuous series of at least 10 tests performed on a commercially available gravimetric sulfur standard in the range of 100–200 ppm sulfur shall not differ from the ARV of that standard by more than 7.26 ppm sulfur;

(ii) The arithmetic average of a continuous series of at least 10 tests performed on a commercially available gravimetric sulfur standard in the range of 400–500 ppm sulfur shall not differ from the ARV of that standard by more than 7.26 ppm sulfur; and

(iii) In applying the tests of paragraphs (b)(2)(i) and (ii) of this section, individual test results shall be compensated for any known chemical interferences.

■ 47. A new § 80.585 is added to read as follows:

§ 80.585 What is the process for approval of a test method for determining the sulfur content of diesel?

(a) *Approval of test methods approved by voluntary consensus-based standards bodies.* For such a method to be approved, the following information must be submitted to the Administrator by each test facility for each test method that it wishes to have approved: Any test method approved by a voluntary consensus-based standards body, such as the American Society for Testing and Materials (ASTM) or International Standards Organization (ISO), shall be approved as a test method for determining the sulfur content of diesel fuel if it meets the applicable accuracy and precision criteria under § 80.584. The approval of a test method is limited to the single test facility that performed the testing for accuracy and precision. The individual facility must submit the accuracy and precision results for each method, including information on the date and time of each test measurement used to demonstrate precision, following procedures established by the Administrator.

(b) *Approval of test methods not approved by a voluntary consensus-based standards body.* For such a method to be approved, the following information must be submitted to the Administrator by each test facility for each test method that it wishes to have approved:

(1) Full test method documentation, including a description of the technology and/or instrumentation that makes the method functional.

(2) Information demonstrating that the test method meets the applicable accuracy and precision criteria of § 80.584, including information on the date and time of each test measurement used to demonstrate precision.

(3) If requested by the Administrator, test results from use of the method to analyze samples of commercially available fuel provided by EPA.

(4) Any additional information requested by the Administrator and necessary to render a decision as to approval of the test method.

(c) *Sample retention.* Samples used for precision and accuracy determination must be retained for 90 days.

(d) *EPA approval.* (1) Within 90 days of receipt of all materials required to be submitted under paragraph (a) or (b) of this section, the Administrator shall determine whether the test method is approved under this section.

(2) If the Administrator denies approval of the test method, within 90 days of receipt of all materials required to be submitted under paragraph (a) or (b) of this section, the Administrator will notify the applicant of the reasons for not approving the method. If the Administrator does not notify the applicant within 90 days of receipt of the application, that the test method is not approved, then the test method shall be deemed approved.

(3) If the Administrator finds that an individual test facility has provided false or inaccurate information under this section, upon notice from the Administrator the approval shall be void *ab initio.*

(4) The approval of any test method under paragraph (b) of this section shall be valid for five years from the date of approval by the Administrator and shall not be extended. If the method is later approved by a voluntary consensus-based standards body, the approval shall remain valid as long as the conditions of paragraph (a) of this section are met.

(e) *Quality assurance procedures for sulfur measurement instrumentation.* A test shall not be considered a test using an approved test method unless the following quality control procedures are performed separately for each instrument used to make measurements:

(1) Follow all mandatory provisions of ASTM D 6299–02 and construct control charts from the mandatory quality control testing prescribed in paragraph

7.1 of the reference method, following guidelines under A 1.5.1 for individual observation charts and A 1.5.2 for moving range charts. The Director of the Federal Register approved the incorporation by reference of ASTM D 6299–02, Standard Practice for Applying Statistical Quality Assurance Techniques to Evaluate Analytical Measurement System Performance, as prescribed in 5 U.S.C. 552(a) and 1 CFR part 51. Anyone may purchase copies of this standard from the American Society for Testing and Materials, 100 Barr Harbor Dr., West Conshohocken, PA 19428. Anyone may inspect copies at the U.S. EPA, Air and Radiation Docket and Information Center, 1301 Constitution Ave., NW., Room B102, EPA West Building, Washington, DC 20460 or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(2) Follow paragraph 7.3.1 of ASTM D 6299–02 to check standards using a reference material at least monthly or following any major change to the laboratory equipment or test procedure. Any deviation from the accepted reference value of a check standard greater than 1.44 ppm (for diesel fuel subject to the 15 ppm sulfur standard) or 19.36 ppm (for diesel fuel subject to the 500 ppm sulfur standard) must be investigated.

(3) Samples of tested batches must be retained for 30 days or the period equal to the interval between quality control sample tests, whichever is longer.

(4) Upon discovery of any quality control testing violation of paragraph A 1.5.1.3 or A 1.5.2.1 of ASTM D 6299–02, or any check standard deviation greater than 1.44 ppm (for diesel fuel subject to the 15 ppm sulfur standard) or 19.36 ppm (for diesel fuel subject to the 500 ppm sulfur standard), conduct an investigation into the cause of such violation or deviation and, after restoring method performance to statistical control, retest retained samples from batches originally tested since the last satisfactory quality control material or check standard testing occasion.

■ 48. A new § 80.586 is added to read as follows:

§ 80.586 What are record retention requirements for test methods approved under this subpart?

Each individual test facility must retain records related to the establishment of accuracy and precision values, all test method documentation, and any quality control testing and analysis under §§ 80.582, 80.584 and 80.585, for five years.

■ 49. Section 80.590 is revised to read as follows:

§ 80.590 What are the product transfer document requirements for motor vehicle diesel fuel, NRLM diesel fuel, heating oil and other distillates?

(a) On each occasion that any person transfers custody or title to MVNRLM diesel fuel or heating oil, including distillates used or intended to be used as MVNRLM diesel fuel or heating oil, except when such fuel is dispensed into motor vehicles or nonroad, locomotive, or marine equipment, the transferor must provide to the transferee documents which include the following information:

(1) The names and addresses of the transferor and transferee.

(2) The volume of diesel fuel or distillate which is being transferred.

(3) The location of the diesel fuel or distillate at the time of the transfer.

(4) The date of the transfer.

(5) For transfers of MVNRLM diesel fuel, the sulfur content standard the transferor represents the fuel to meet.

(6) Beginning June 1, 2006, when an entity transfers custody of a distillate fuel designated under § 80.598, the following information must also be included:

(i) The facility registration number of the transferor issued under § 80.597, if any.

(ii) An accurate and clear statement of the applicable designation and/or classification under § 80.598, for example, 500 ppm sulfur NRLM diesel fuel; and whether the fuel is dyed or undyed, and for heating oil, whether marked or unmarked.

(7) For transfers of title or custody from one facility to another in the distribution system where diesel fuel or distillates are taxed, dyed or marked, and for any subsequent transfers (except when such fuel is dispensed into motor vehicles or nonroad, locomotive or marine equipment), an accurate statement on the product transfer document of the applicable fuel uses and classifications, as follows:

(i) *Undyed 15 ppm sulfur diesel fuel.* For the period from June 1, 2006 and beyond, "15 ppm sulfur (maximum) Undyed Ultra-Low Sulfur Diesel Fuel For use in all diesel vehicles and engines." From June 1, 2006 through May 31, 2010, the product transfer document must also state whether the diesel fuel is #1D or #2D.

(ii) *Dyed 15 ppm sulfur diesel fuel.* From June 1, 2006 and beyond, "15 ppm sulfur (maximum) Dyed Ultra-Low Sulfur Diesel Fuel. For use in all nonroad diesel engines. Not for use in highway vehicles or engines except for tax-exempt use in accordance with section 4082 of the Internal Revenue Code."

(iii) *Undyed 500 ppm sulfur diesel fuel.* From June 1, 2006 through September 30, 2010, "500 ppm sulfur (maximum) Undyed Low Sulfur Diesel Fuel. For use in Model Year 2006 and older diesel highway vehicles and engines. Also for use in nonroad, locomotive, and marine diesel engines. Not for use in model year 2007 and newer highway vehicles or engines."

(iv) *Dyed 500 ppm sulfur diesel fuel.* (A) For the period of June 1, 2006 through September 30, 2010, "500 ppm sulfur (maximum) Dyed Low Sulfur Nonroad, Locomotive or Marine Diesel Fuel. Not for use in highway vehicles or engines except for use in Model Year 2006 and older highway diesel vehicles or engines for tax-exempt use in accordance with section 4082 of the Internal Revenue Code."

(B) From June 1, 2010 through September 30, 2014, "500 ppm sulfur (maximum) Dyed Low Sulfur Nonroad Diesel Fuel. For use in model year 2010 and older nonroad diesel engines. May be used in locomotive and marine diesel engines. Not for use in highway vehicles and engines or model year 2011 or later nonroad engines other than locomotive or marine diesel engines. Not for use in the Northeast/Mid-Atlantic Area."

(C) For dyed locomotive and marine diesel fuel beginning June 1, 2010, "500 ppm sulfur (maximum) Dyed Low Sulfur Locomotive and Marine diesel fuel. Not for use in highway or other nonroad vehicles and engines."

(v) *Dyed High Sulfur NRLM Fuel.* From June 1, 2007 through September 30, 2010, "High Sulfur Dyed Nonroad, Locomotive, or Marine Engine Diesel fuel—sulfur content may exceed 500 ppm sulfur. Not for use in highway vehicles or engines. Not for use in any nonroad engines requiring Ultra-Low Sulfur Diesel Fuel. Not for use in the Northeast/Mid-Atlantic Area."

(vi) *Heating oil.* For heating oil produced or imported beginning June 1, 2007, "Heating Oil. Not for use in highway vehicles or engines or nonroad, locomotive, or marine engines."

(b) The following may be substituted for the descriptions in paragraph (a) of this section, as appropriate:

(1) "This is high sulfur diesel fuel for use only in Guam, American Samoa, or the Northern Mariana Islands.";

(2) "This diesel fuel is for export use only.";

(3) "This diesel fuel is for research, development, or testing purposes only."; or

(4) "This diesel fuel is for use in diesel highway vehicles or nonroad equipment under an EPA-approved national security exemption only."

(c) If undyed and/or unmarked distillate fuel is dyed and/or marked subsequent to the issuance of a product transfer document, at the time the distillate fuel is dyed and/or marked, a new product transfer document must be prepared with the language under paragraph (a)(7) of this section applicable to the changed fuel and provided to subsequent transferees.

(d) Except for transfers to truck carriers, retailers or wholesale purchaser-consumers, product codes may be used to convey the information required under this section if such codes are clearly understood by each transferee. Codes used to convey the statement in paragraphs (a)(7)(i) and (ii) of this section must contain the number "15", and codes used to convey the statement in paragraphs (a)(7)(iii) and (iv) of this section must contain the number "500". Codes used to convey the statement in paragraph (a)(7)(v) of this section must contain the statement "greater than 500" or ">500".

(e) From June 1, 2001 through May 31, 2005, any transfer subject to this section, which is also subject to the early credit provisions of § 80.531(b), must comply with all applicable requirements of this section.

(f) From June 1, 2005 through May 31, 2006, any transfer subject to this section, which is also subject to the early credit requirements of § 80.531(c), must comply with all applicable requirements of this section.

(g) *Mobile refuelers.* The provisions of this section shall also apply to a mobile refueler that dispenses fuel from tanker trucks or other vessels into motor vehicles, nonroad diesel engines or nonroad diesel engine equipment. Each visit by the mobile refueler to a location shall be considered a separate occasion for purposes of paragraph (a) of this section. The tank trucks used by mobile refuelers are not subject to the labeling requirements in §§ 80.570 through 80.574.

(h) Identifications of fuel designations can be limited to a sub-designation that accurately identifies the fuel and do not need to also include the broader designation. For example, NR diesel fuel does not also need to be designated as NRLM or MVNRLM diesel fuel.

■ 50. Section 80.591 is revised to read as follows:

§ 80.591 What are the product transfer document requirements for additives to be used in diesel fuel?

(a) Except as provided in paragraphs (b) and (d) of this section, on each occasion that any person transfers custody or title to a diesel fuel additive that is subject to the provisions of § 80.521 to a party in the additive distribution system or in the diesel fuel distribution system for use downstream of the diesel fuel refiner, the transferor must provide to the transferee documents which identify the additive, and—

(1) Identify the name and address of the transferor and transferee; the date of transfer; the location at which the transfer took place; the volume of additive transferred; and

(2) Indicate compliance with the 15 ppm sulfur standard by inclusion of the following statement: "The sulfur content of this diesel fuel additive does not exceed 15 ppm."

(b) On each occasion that any person transfers custody or title to a diesel fuel additive subject to the requirements of § 80.521(b), to a party in the additive distribution system or in the diesel fuel distribution system for use in diesel fuel downstream of the diesel fuel refiner, the transferor must provide to the transferee documents which identify the additive, and do each of the following:

(1) Identify the name and address of the transferor and transferee; the date of transfer; the location at which the transfer took place; the volume of additive transferred.

(2) Indicate the high sulfur potential of the additive by inclusion of the following statement:

This diesel fuel additive may exceed the federal 15 ppm sulfur standard. Improper use of this additive may result in non-complying diesel fuel.

(3) If the additive contains a static dissipater additive having a sulfur content greater than 15 ppm, include the following statement:

This diesel fuel contains a static dissipater additive having a sulfur content greater than 15 ppm.

(4) Include the following information:

(i) The additive's maximum sulfur concentration.

(ii) The maximum recommended concentration in volume percent for use of the additive in diesel fuel.

(iii) The contribution to the sulfur level of the fuel, in ppm, that would result if the additive is used at the maximum recommended concentration.

(c) Except for transfers of diesel fuel additives to truck carriers, retailers or wholesale purchaser-consumers, product codes may be used to convey the information required under paragraphs (a) and (b) of this section, if such codes are clearly understood by each transferee. Codes used to convey the statement in paragraph (a)(2) of this section must contain the number "15" and codes used to convey the statement in paragraph (b)(2) of this section must not contain such number.

(d) For those diesel fuel additives which are sold in containers for use by the ultimate consumer of diesel fuel, each transferor must have displayed on the additive container, in a legible and conspicuous manner, either of the following statements, as applicable:

(1) "This diesel fuel additive complies with the federal low sulfur content requirements for use in diesel motor vehicles and nonroad engines."; or

(2) For those additives sold in containers for use by the ultimate consumer, with a sulfur content in excess of 15 ppm the following statement: "This diesel fuel additive does not comply with federal ultra-low sulfur content requirements for use in model year 2007 and newer diesel motor vehicles or model year 2011 and newer diesel nonroad equipment engines."

■ 51. Section 80.592 is amended by revising the heading and paragraphs (a), (b) introductory text, (b)(4), (b)(7) introductory text, (c), (d), and (e) to read as follows:

§ 80.592 What records must be kept by entities in the motor vehicle diesel fuel and diesel fuel additive distribution systems?

(a) *Records that must be kept by entities in the motor vehicle diesel fuel and diesel fuel additive distribution systems.* Beginning June 1, 2006, or for a refiner or importer, the first compliance period in which the refiner or importer is generating early credits under § 80.531(b) or (c), whichever is earlier, any person who produces, imports, sells, offers for sale, dispenses, distributes, supplies, offers for supply, stores, or transports motor vehicle diesel fuel subject to the provisions of this subpart, must keep all the following records:

(1) The applicable product transfer documents required under §§ 80.590 and 80.591.

(2) For any sampling and testing for sulfur content for a batch of motor vehicle diesel fuel produced or imported and subject to the 15 ppm sulfur standard or any sampling and testing for sulfur content as part of a quality assurance testing program, and any sampling and testing for cetane index, aromatics content, solvent yellow 124 content or dye solvent red 164

content of motor vehicle diesel fuel or motor vehicle diesel fuel additives:

(i) The location, date, time and storage tank or truck identification for each sample collected;

(ii) The name and title of the person who collected the sample and the person who performed the testing; and

(iii) The results of the tests for sulfur content (including where applicable the test results with and without application of the adjustment factor under § 80.580(a)(4)) and for cetane index or aromatics content (as applicable), and the volume of product in the storage tank or container from which the sample was taken.

(3) The actions the party has taken, if any, to stop the sale or distribution of any motor vehicle diesel fuel found not to be in compliance with the sulfur standards specified in this subpart, and the actions the party has taken, if any, to identify the cause of any noncompliance and prevent future instances of noncompliance.

(b) *Additional records to be kept by refiners and importers of motor vehicle diesel fuel subject to hardship standards, small refiner standards and early credit provisions.* Beginning June 1, 2006, or for a refiner or importer, the first compliance period in which the refiner or importer is generating early credits under § 80.531(b) or (c), any refiner producing motor vehicle diesel fuel subject to the sulfur standard under § 80.520(a)(1), for each of its refineries, and any importer importing such motor vehicle diesel fuel, shall keep records that include the following information for each batch of motor vehicle diesel fuel produced or imported: * * *

(4) A record designating the batch as motor vehicle diesel fuel meeting the 500 ppm sulfur standard or as motor vehicle diesel fuel meeting the 15 ppm sulfur standard.

* * * * *

(7) Information regarding credits, kept separately for each calendar year compliance period, kept separately for each refinery and in the case of importers, kept separately for imports into each CTA, and designated as motor vehicle diesel fuel credits and kept separately from NRLM credits, as follows:

* * * * *

(c) *Additional records importers must keep.* Any importer shall keep records that identify and verify the source of each batch of certified diesel fuel program foreign refiner DFR-Diesel and non-certified DFR-Diesel imported and demonstrate compliance with the requirements under § 80.620.

(d) *Length of time records must be kept.* The records required in this section shall be kept for five years from the date they were created, except that records relating to credit transfers shall be kept by the transferor for 5 years from the date the credits were transferred, and shall be kept by the transferee for 5 years from the date the credits were transferred, used or terminated, whichever is later.

(e) *Make records available to EPA.* On request by EPA, the records required in this section must be made available to the Administrator or the Administrator's representative. For records that are electronically generated or maintained, the equipment and software necessary to read the records shall be made available, or if requested by EPA, electronic records shall be converted to paper documents which shall be provided to the Administrator's authorized representative.

■ 52. Section 80.593 is amended by revising the section heading and paragraphs (a)(3) and (c)(2) to read as follows:

§ 80.593 What are the reporting requirements for refiners and importers of motor vehicle diesel fuel subject to temporary refiner relief standards?

* * * * *

(a) * * *

(3) The percentage of the volume of motor vehicle diesel fuel produced during the compliance period that met the 15 ppm sulfur standard and the percentage that met the 500 ppm sulfur standard prior to the application of any volume credits.

* * * * *

(c) * * *

(2) Submitted to EPA no later than August 31 for the prior annual compliance period.

■ 53. Section 80.594 is amended by revising the section heading and paragraphs (a)(3), (a)(5), (b) introductory text, (b)(2), and (c), and adding paragraphs (a)(6), (a)(7), (a)(8), and (e) to read as follows:

§ 80.594 What are the pre-compliance reporting requirements for motor vehicle diesel fuel?

(a) Except as provided in paragraph (d) of this section, beginning on June 1, 2003, and on June 1, 2004 and June 1, 2005, all refiners and importers planning to produce or import motor vehicle diesel fuel subject to the provisions of this subpart, shall submit the following information to EPA:

* * * * *

(3) An estimate of the average daily volumes (in gallons) of each sulfur grade of motor vehicle diesel fuel produced (or imported) at each refinery (or import facility). These volume estimates must be provided both for fuel produced from crude oil, as well as any fuel produced from other sources, and must be provided for the periods of June 1, 2006 through December 31, 2006, January 1, 2007 through December 31, 2007, January 1, 2008 through December 31, 2008, January 1, 2009 through December 31, 2009, and January 1, 2010 through May 31, 2010, for each refinery and import facility;

* * * * *

(5) Information on project schedule by quarter of known or projected completion date by the stage of the project, for example, following the five project phases described in EPA's June 2002 Highway Diesel Progress Review report (EPA420–R–02–016, *http://www.epa.gov/otaq/regs/hd2007/420r02016.pdf*): Strategic planning, Planning and front-end engineering, Detailed engineering and permitting, Procurement and construction, and Commissioning and startup;

(6) Basic information regarding the selected technology pathway for compliance (*e.g.*, conventional hydrotreating vs other technologies, revamp vs grassroots, *etc.*);

(7) Whether capital commitments have been made or are projected to be made; and

(8) The pre-compliance reports due 2004 and 2005 must provide an update of the progress in each of these areas.

(b) Beginning on June 1, 2003, all approved motor vehicle diesel fuel small refiners shall submit the following additional information to EPA, as applicable:

* * * * *

(2) In case of a refinery with an approved application under § 80.552(c), a demonstration that by June 1, 2006 its motor vehicle diesel fuel will be at 15 ppm sulfur at a volume meeting the requirements of § 80.553(e).

(c) For each refiner and importer approved under § 80.540, a demonstration that by June 1, 2006, 95 percent of its motor vehicle diesel fuel will be at 15 ppm sulfur at a volume of meeting the requirements of § 80.540(e).

* * * * *

(e) The pre-compliance reporting requirements of this section do not apply to refineries subject to the provisions of § 80.513.

■ 54. Section 80.597 is revised to read as follows:

§ 80.597 What are the registration requirements?

The following registration requirements apply under this subpart:

(a) *Registration for motor vehicle diesel fuel.* Refiners having any refinery that is subject to a sulfur standard under § 80.520(a), and importers importing such diesel fuel, must provide EPA the information under § 80.76, if such information has not been provided under the provisions of this part. In addition, for each import facility, the same identifying information as required for each refinery under § 80.76(c) must be provided.

(b) *Registration for NRLM diesel.* Refiners and importers that intend to produce or supply NRLM diesel fuel by June 1, 2007, must provide EPA the information under § 80.76 no later than December 31, 2005, if such information has not been provided under the provisions of this part. In addition, for each import facility, the same identifying information as required for each refinery under § 80.76(c) must be provided.

(c) *Entity registration.* (1) Each entity as defined in § 80.502 that intends to deliver or receive custody of any of the following fuels from June 1, 2007 through May 31, 2014 must register with EPA by December 31, 2005 or six months prior to commencement of producing, importing, or distributing any distillate subject to designation under § 80.598:

(i) Fuel designated as 500 ppm sulfur MVNRLM diesel fuel under § 80.598 on which taxes have not been assessed pursuant to IRS code (26 CFR part 48).

(ii) Fuel designated as NRLM diesel fuel under § 80.598 that is undyed pursuant to § 80.520.

(iii) Fuel designated as heating oil under § 80.598 that is unmarked pursuant to § 80.510(d) through (f).

(iv) Fuel designated as LM diesel fuel under § 80.598(a)(2)(iii) that is unmarked pursuant to § 80.510(e).

(2) Registration shall be on forms prescribed by the Administrator, and shall include the name, business address, contact name, telephone number, e-mail address, and type of production, importation, or distribution activity or activities engaged in by the entity.

(3) Registration shall include the information required under paragraph (d) of this section for each facility owned or operated by the entity that delivers or receives custody of a fuel described in paragraph (c)(1) of this section.

(d) *Facility registration.* (1) List for each separate facility of an entity required to register under paragraph (c) of this section, the facility name, physical location, contact name, telephone number, e-mail address and type of facility. For facilities that are aggregated under § 80.502, provide information regarding the nature and location of each of the components. If aggregation is changed for any subsequent compliance period, the entity must provide notice to EPA prior to the beginning of such compliance period.

(2) If facility records are kept off-site, list the off-site storage facility name, physical location, contact name, and telephone number.

(e) *Changes to registration information.* Any company or entity shall submit updated registration information to the Administrator within 30 days of any occasion when the registration information previously supplied for an entity, or any of its registered facilities, becomes incomplete or inaccurate.

(f) *Issuance of registration numbers.* EPA will supply a registration number to each entity and a facility registration number to each of an entity's facilities that is identified, which shall be used in all reports to the Administrator.

■ 55. A new § 80.598 is added to read as follows:

§ 80.598 What are the designation requirements for refiners, importers, and distributors?

(a) *Designation requirements for refiners and importers.* (1) Any refiner or importer shall accurately and clearly designate all fuel it produces or imports for use in diesel motor vehicles as either motor vehicle diesel fuel meeting the 15 ppm sulfur standard under § 80.520(a)(1) or as motor vehicle diesel fuel meeting the 500 ppm sulfur standard under § 80.520(c).

(2) Subject to the restrictions in paragraph (a)(3) of this section, beginning June 1, 2006, any refiner or importer shall accurately and clearly designate each batch of diesel fuel or distillate fuel for which they transfer custody to another entity, according to the following categories, including specifying its volume:

(i) Designate the fuel as one of the following fuel types:

(A) Motor vehicle, nonroad, locomotive or marine (MVNRLM) diesel fuel;

(B) Heating oil;

(C) Jet fuel;

(D) Kerosene;

(E) No. 4 fuel;

(F) Distillate fuel for export only; or

(G) Exempt distillate fuels such as fuels that are covered by a national security exemption under § 80.606, fuels that are used for purposes of research and development pursuant to § 80.607, and fuels used in the U.S. Territories pursuant to § 80.608 (including additional identifying information).

(ii) From June 1, 2006 through May 31, 2014 any batch designated as MVNRLM diesel fuel must also be designated as one of the following:

(A) Motor vehicle diesel fuel; or

(B) NRLM diesel fuel.

(iii) From June 1, 2010 through May 31, 2012 any batch designated as NRLM must also be designated as one of the following:

(A) NR diesel fuel; or

(B) LM diesel fuel.

(iv) Until June 1, 2014, any batch designated as MVNRLM diesel fuel must also be designated according to one of the following three sulfur level specifications:

(A) 15 ppm if its sulfur content is less than or equal to 15 ppm.

(B) 500 ppm if its sulfur content is less than or equal to 500 ppm.

(C) High Sulfur if its sulfur content is greater than 500 ppm.

(v) From June 1, 2006 through May 31, 2010, any batch designated as motor vehicle diesel fuel must also be designated according to one of the following two distillation classifications that most accurately represents the fuel:

(A) #1D.

(B) #2D.

(3) The following restrictions and clarifications apply:

(i) Prior to June 1, 2006, any batch of MVNRLM not containing visible evidence of red dye under § 80.520(b) must be designated as motor vehicle diesel fuel.

(ii) Any distillate fuel containing visible evidence of dye may not be designated as motor vehicle diesel fuel unless it is further designated as tax exempt motor vehicle diesel fuel.

(iii) Any distillate containing the marker required pursuant to the provisions of § 80.510(d) through (f) must be designated as heating oil, except that from June 1, 2010 through May 31, 2012 it may also be designated as LM diesel fuel, pursuant to § 80.510(e).

(iv) Prior to June 1, 2009 all 15 ppm sulfur MVNRLM diesel fuel must be designated as motor vehicle diesel fuel.

(v) Beginning June 1, 2010 any distillate fuel having a sulfur content greater than 15 ppm may not be designated as motor vehicle diesel fuel.

(vi) Beginning June 1, 2014, any distillate fuel having a sulfur content greater than to 15 ppm may not be designated as MVNRLM diesel fuel.

(vii) Any batch of #1D fuel which is suitable for use as MVNRLM and which is also suitable for use as kerosene or jet fuel (*i.e.,* commonly referred to as dual use kerosene) may be designated as MVNRLM, kerosene, or jet fuel (as applicable).

(viii) Beginning June 1, 2007, any distillate fuel with a sulfur content greater than 500 ppm distributed or intended for distribution in the area specified in § 80.510(g)(1), may not be designated as MVNRLM diesel fuel.

(ix) From June 1, 2010 through May 31, 2012, any distillate fuel with a sulfur content greater than 15 ppm distributed or intended for distribution in the area specified in § 80.510(g)(1), may not be designated as NR diesel fuel.

(x) From June 1, 2012 through May 31, 2014, any distillate fuel with a sulfur content greater than 15 ppm distributed or intended for distribution in the area specified in § 80.510(g)(1), may not be designated as NRLM diesel fuel.

(xi) Beginning June 1, 2007, any distillate fuel with a sulfur content greater than 500 ppm distributed or intended for distribution in the area specified in § 80.510(g)(2) may not be designated as NRLM diesel fuel unless EPA has first approved a compliance plan for the refiner for segregating the fuel from all other types of NRLM diesel fuel from the refinery gate to the ultimate consumer, as specified under § 80.554(a)(4).

(xii) From June 1, 2010 through May 31, 2012, any distillate fuel with a sulfur content greater than 15 ppm distributed or intended for distribution in the area specified in § 80.510(g)(2) may not be designated as NR diesel fuel unless EPA has first approved a compliance plan for the refiner for segregating the fuel from all other types of NRLM diesel fuel from the refinery gate to the ultimate consumer, as specified under § 80.554(b)(4).

(xiii) From June 1, 2012 through May 31, 2014, any distillate fuel with a sulfur content greater than 15 ppm distributed or intended for distribution in the area specified in § 80.510(g)(2) may not be designated as NRLM diesel fuel unless, EPA has first approved a compliance plan for the refiner for segregating the fuel from all other types of NRLM diesel fuel from the refinery gate to the ultimate consumer, as specified under § 80.554(b)(4).

(xiv) Beginning June 1, 2014, any distillate fuel with a sulfur content greater than 15 ppm may not be designated as MVNRLM diesel fuel.

(b) *Designation requirements for fuel distributors.* (1) Pursuant to the provisions of paragraphs (b)(2) through (b)(9) of this section, beginning June 1, 2006, any distributor shall accurately and clearly designate each batch of diesel fuel or distillate fuel for which they transfer custody to another facility, including specifying its volume, as specified in this paragraph (b). Distributors must also accurately and clearly classify such diesel fuel and distillate fuel by sulfur content, while it is in their custody between receipt and delivery.

(2) From June 1, 2006 through May 31, 2009, whenever custody of a batch of 15 ppm sulfur motor vehicle diesel fuel is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) #1D 15 ppm sulfur motor vehicle diesel fuel.

(ii) #2D 15 ppm sulfur motor vehicle diesel fuel.

(3) From June 1, 2009 through May 31, 2010, whenever custody of a batch of 15 ppm sulfur MVNRLM diesel fuel is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) #1D 15 ppm sulfur motor vehicle diesel fuel.

(ii) #2D 15 ppm sulfur motor vehicle diesel fuel.

(iii) 15 ppm sulfur NRLM diesel fuel.

(4) From June 1, 2006 through May 31, 2010, whenever custody of a batch of undyed, 500 ppm sulfur MVNRLM is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) #1D 500 ppm sulfur motor vehicle diesel fuel;

(ii) #2D 500 ppm sulfur motor vehicle diesel fuel; or

(iii) 500 ppm sulfur NRLM diesel fuel.

(5) From June 1, 2007 through May 31, 2010, whenever custody of a batch of distillate fuel (other than jet fuel, kerosene, No. 4 fuel, or fuel for export) having a sulfur content greater than 500 ppm is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) High sulfur NRLM diesel fuel (HSNRLM);

(ii) Heating oil; or

(iii) Exempt distillate fuels such as fuels that are covered by a national security exemption under § 80.606, fuels that are used for purposes of research and development pursuant to § 80.607, and fuels used in the U.S. Territories pursuant to § 80.608 (including additional identifying information).

(6) From June 1, 2010 through May 31, 2012, whenever custody of a batch of distillate fuel (other than jet fuel, kerosene, No. 4 fuel, or fuel for export) having a sulfur content greater than 15 ppm is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) 500 ppm sulfur NR diesel fuel;

(ii) 500 ppm sulfur LM diesel fuel;

(iii) Heating oil; or

(iv) Exempt distillate fuels such as fuels that are covered by a national security exemption under § 80.606, fuels that are used for purposes of research and development pursuant to § 80.607, and fuels used in the U.S. Territories pursuant to § 80.608 (including additional identifying information).

(7) From June 1, 2012 through May 31, 2014, whenever custody of a batch of distillate fuel (other than jet fuel, kerosene, No. 4 fuel, or fuel for export) having a sulfur content greater than 15 ppm is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) 500 ppm sulfur NRLM diesel fuel;

(ii) Heating oil; or

(iii) Exempt distillate fuels such as fuels that are covered by a national security exemption under § 80.606, fuels that are used for purposes of research and development pursuant to § 80.607, and fuels used in the U.S. Territories pursuant to § 80.608 (including additional identifying information).

(8) Beginning June 1, 2014, whenever custody of a batch of distillate fuel (other than jet fuel, kerosene, No. 4 fuel, or fuel for export) having a sulfur content greater than 15 ppm is transferred to another facility, the entity transferring custody must accurately and clearly designate the batch as one of the following and specify its volume:

(i) 500 ppm sulfur LM diesel fuel;

(ii) Heating oil; or

(iii) Exempt distillate fuels such as fuels that are covered by a national security exemption under § 80.606, fuels that are used for purposes of research and development pursuant to § 80.607, and fuels used in the U.S. Territories pursuant to § 80.608 (including additional identifying information).

(9) The following restrictions and clarifications apply. Subject to the provisions of this paragraph (b)(9) and subject to the dye and marker provisions of § 80.520(b) and § 80.510(d) through (f), when custody of a batch of distillate fuel is transferred, the designation provided by the entity transferring custody pursuant to paragraphs (b)(1) through (b)(8) of this section may be different from the designation of the fuel when that same entity received custody.

(i) Any 500 ppm sulfur diesel fuel designated under this paragraph (b) and containing visible evidence of red dye may not be designated as motor vehicle diesel fuel.

(ii) Any distillate fuel containing greater than or equal to 0.10 milligrams per liter of marker solvent yellow 124 required under § 80.510(d), (e), or (f) must be designated as heating oil except that from June 1, 2010 through October 1, 2012 it may also be designated as LM diesel fuel as specified under § 80.510(e).

(iii) Any batch of #1D fuel which is suitable for use as MVNRLM diesel fuel and which is also suitable for use as kerosene or jet fuel (*i.e.*, commonly referred to as dual use kerosene) may be designated as either MVNRLM diesel fuel, kerosene, or jet fuel (as applicable).

(iv) Any MVNRLM diesel fuel with a sulfur content of 500 ppm or less in inventory as of June 1, 2007 may be designated as motor vehicle diesel fuel.

(v) Batches or portions of batches of fuel received designated as 15 ppm sulfur #2D motor vehicle diesel fuel may be re-designated as 500 ppm sulfur motor vehicle diesel fuel, but only in accordance with the limitations of § 80.527(c).

(vi) Batches or portions of batches received designated as 500 ppm sulfur NRLM diesel fuel may be re-designated as 500 ppm sulfur motor vehicle diesel fuel by a truck loading terminal only if the terminal maintains a neutral or positive balance at the end of each quarterly compliance period on their motor vehicle diesel fuel volume from June 1, 2007 as calculated in § 80.599(b)(4).

(vii) Batches or portions of batches received designated as 500 ppm sulfur NRLM diesel fuel may be re-designated as 500 ppm sulfur motor vehicle diesel fuel by a facility other than a truck loading terminal only if the following restrictions are met:

(A) At the end of each annual compliance period, the facility has a neutral or positive balance on its motor vehicle diesel fuel volume from June 1, 2007 as calculated in § 80.599(b)(4); and

(B) At the end of each annual compliance period, the facility's balance for motor vehicle diesel fuel volume, from the beginning of the compliance period must be less than two percent of the total volume of motor vehicle diesel fuel received during the compliance period, as calculated in § 80.599(b)(5).

(viii) For facilities in areas other than those specified in § 80.510(g)(1) and (g)(2), batches or portions of batches of unmarked distillate received designated as heating oil may be re-designated as NRLM or LM diesel fuel only if the following restrictions are met:

(A) From June 1, 2007 through May 31, 2010, for any compliance period, the volume of high sulfur NRLM diesel fuel delivered from a facility cannot be greater than the volume received, unless the volume of heating oil delivered from the facility is also greater than the volume it received by an equal or greater proportion, as calculated in § 80.599(c)(2); and

(B) Beginning June 1, 2010, for any compliance period, the volume of fuel designated as heating oil delivered from a facility cannot be less than the volume of fuel designated as heating oil received, as calculated in § 80.599(c)(4).

(ix) For facilities in areas other than those specified in § 80.510(g)(1) and (g)(2), from June 1, 2010 through May 31, 2012, batches or portions of batches received designated as 500 ppm LM diesel fuel may be redesignated as 500 ppm NR diesel fuel only if for any compliance period the following restrictions are met:

(A) The volume of fuel designated as 500 ppm sulfur NR diesel fuel delivered from the facility cannot be greater than the volume received as calculated in § 80.599(d)(2)(i); or

(B) The volume of fuel designated as 500 ppm sulfur NR diesel fuel delivered from the facility in relation to the volume received is not a greater proportion than the volume of fuel designated as 500 ppm sulfur LM diesel fuel delivered from the facility in relation to the volume received, as calculated in § 80.599(d)(2)(ii).

(x) Notwithstanding the provisions of paragraph (b)(5) of this section, beginning October 1, 2007,

(A) No distillate fuel with a sulfur content greater than 500 ppm distributed or intended for distribution in the areas specified in § 80.510(g)(1) and (g)(2), may be designated as NRLM diesel fuel, including LM diesel fuel except as provided in paragraph (b)(9)(xiii) of this section; and

(B) Distillate fuel with a sulfur content greater than 500 ppm distributed from within the areas specified in § 80.510(g)(1) and (g)(2) to areas outside these areas is subject to the provisions of paragraph (b)(5) of this section.

(xi) Notwithstanding the provisions of paragraphs (b)(6) through (b)(8) of this section, beginning October 1, 2010—

(A) No distillate fuel with a sulfur content greater than 15 ppm distributed or intended for distribution in the areas specified in § 80.510(g)(1) and (g)(2), may be designated as NR diesel fuel, except as provided in paragraph (b)(9)(xiv) of this section; and

(B) Distillate fuel with a sulfur content greater than 15 ppm distributed from within the areas specified in § 80.510(g)(1) and (g)(2) to areas outside these areas is subject to the provisions of paragraphs (b)(6) through (b)(7) of this section.

(xii) Notwithstanding the provisions of paragraphs (b)(7) and (8) of this section, beginning October 1, 2012—

(A) No distillate fuel with a sulfur content greater than 15 ppm distributed or intended for distribution in the areas specified in § 80.510(g)(1) and (g)(2), may be designated as NRLM diesel fuel, including LM diesel fuel, except as provided in paragraph (b)(9)(xv) of this section; and

(B) Distillate fuel with a sulfur content greater than 15 ppm distributed from within the areas specified in § 80.510(g)(1) and (g)(2) to areas outside these areas is subject to the provisions of paragraphs (b)(7) and (8) of this section.

(xiii) From June 1, 2007 through September 30, 2010, in the area specified in § 80.510(g)(2) only segregated batches of distillate fuel received designated as HSNRLM diesel fuel may be distributed designated as HSNRLM diesel fuel and must remain segregated from fuel with any other designations unless otherwise approved by EPA in a refiner compliance plan under § 80.554(a)(4).

(xiv) From June 1, 2010 through September 30, 2012, in the area specified in § 80.510(g)(2) only segregated batches of distillate fuel received designated as 500 ppm sulfur NR diesel fuel may be distributed designated as 500 ppm sulfur NR diesel fuel and must remain segregated from fuel with any other designations and from any other 500 ppm sulfur NRLM diesel fuel from any other sources, except as approved by EPA in a refiner compliance plan under § 80.554(a)(4).

(xv) From June 1, 2012 through September 30, 2014, in the area specified in § 80.510(g)(2) only segregated batches of distillate fuel received designated as 500 ppm sulfur NRLM diesel fuel may be distributed designated as 500 ppm sulfur NRLM diesel fuel and must remain segregated from fuel with any other designations and from any other 500 ppm sulfur NRLM diesel fuel from any other sources, except as approved by EPA in a refiner compliance plan under § 80.554(a)(4).

(c) Notwithstanding the provisions of paragraph (b) of this section, an entity is not required to designate heating oil that is delivered from a facility that only receives heating oil which is marked pursuant to § 80.510(d) through (f).

(d) Notwithstanding the provisions of paragraph (b)(4) of this section, an entity is not required to designate 500 ppm sulfur MVNRLM diesel fuel that is delivered from a facility that only receives 500 ppm sulfur MVNRLM diesel fuel on which taxes have been paid or into which red dye has been added pursuant to § 80.520(b).

(e) Notwithstanding the provisions of paragraph (b)(6) of this section, an entity is not required to designate 500 ppm sulfur LM diesel fuel that is delivered from a facility that only receives 500 ppm sulfur LM diesel fuel which is marked pursuant to § 80.510(e).

(f) Any entity that is both a distributor and a refiner or importer must comply with the provisions of paragraph (a) of this section for all distillate fuel produced or imported, and the provisions of paragraph (b) of this section for all distillate fuel for which it acted as distributor but not refiner or importer.

(g) No refiner, importer, or distributor may use the designation provisions of this section to circumvent the standards or requirements of § 80.510, 80.511, or 80.520.

■ 56. A new § 80.599 is added to read as follows:

§ 80.599 How do I calculate volume balances for designation purposes?

(a) *Quarterly compliance periods.* The quarterly compliance periods are shown in the following table:

Beginning date of quarterly compliance period	Ending date of quarterly compliance period
June 1, 2007	September 30, 2007.
October 1, 2007	December 31, 2007.
January 1, 2008	March 31, 2008.
April 1, 2008	June 30, 2008.
July 1, 2008	September 30, 2008.
October 1, 2008	December 31, 2008.
January 1, 2009	March 31, 2009.
April 1, 2009	June 30, 2009.
July 1, 2009	September 30, 2009.
October 1, 2009	December 31, 2009.
January 1, 2010	March 31, 2010.
April 1, 2010	May 31, 2010.
June 1, 2010	September 30, 2010.

(1) *Annual compliance periods.* The annual compliance periods before the period beginning July 1, 2015 are shown in the following table:

Beginning date of annual compliance period	Ending date of annual compliance period
June 1, 2007	June 30, 2008.
July 1, 2008	June 30, 2009.
July 1, 2009	May 31, 2010.
June 1, 2010	June 30, 2011.
July 1, 2011	May 31, 2012.
June 1, 2012	June 30, 2013.
July 1, 2013	May 31, 2014.
June 1, 2014	June 30, 2015.

(2) The annual compliance periods for the period beginning July 1, 2015 shall be from July 1, through June 30.

(b) *Volume balance for motor vehicle diesel fuel.* (1) A facility's motor vehicle diesel fuel volume balance is calculated as follows:

$MVB = MV_I - MV_O - MV_{INVCHG}$

Where:

MVB = the volume balance for motor vehicle diesel fuel for the compliance period.

MV_I = the total volume of all batches of fuel designated as motor vehicle diesel fuel received for the compliance period.

MV_O = the total volume of all batches of fuel designated as motor vehicle diesel fuel delivered for the compliance period.

MV_{INVCHG} = the total volume of 15 ppm sulfur and 500 ppm sulfur motor vehicle diesel fuel in inventory at the end of the compliance period minus the total volume of 15 ppm sulfur and 500 ppm sulfur motor vehicle diesel fuel in inventory at the beginning of the compliance period, including accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

(2) Calculate the motor vehicle diesel fuel received, as follows:

$MV_I = MV15_I + MV500_I$

Where:

$MV15_I$ = the total volume of all batches of fuel designated as 15 ppm sulfur motor vehicle diesel fuel received for the compliance period.

$MV500_I$ = the total volume of all batches of fuel designated as 500 ppm sulfur motor vehicle diesel fuel received for the compliance period.

(3) Calculate the motor vehicle diesel fuel delivered, as follows:

$MV_O = MV15_O + MV500_O$

Where:

$MV15_O$ = the total volume of all batches of fuel designated as 15 ppm sulfur motor vehicle diesel fuel and delivered during the compliance period.

$MV500_O$ = the total volume of all batches of fuel designated as 500 ppm sulfur motor vehicle diesel fuel and delivered during the compliance period.

(4) The neutral or positive volume balance required for purposes of compliance with § 80.598(b)(9)(vi) and (b)(9)(vii)(A) means that the net balance of motor vehicle diesel fuel in inventory as of the end of the last day of the compliance period ($MVNB_E$) must be greater than or equal to zero. $MVNB_E$ is defined by the following equation:

$MVNB_E = MV15_{BINV} + MV500_{BINV}\ \sigma MVB$

Where:

$MV15_{BINV}$ = the total volume of fuel designated as 15 ppm sulfur motor vehicle diesel fuel in inventory at the beginning of the program on June 1, 2007.

$MV500_{BINV}$ = the total volume of fuel designated as 500 ppm sulfur motor vehicle diesel fuel in inventory at the beginning of the program on June 1, 2007. Any #2D 500 ppm sulfur MVNRLM in inventory at the beginning of the program on June 1, 2007 may be designated as motor vehicle diesel fuel.

σMVB = the sum of the balances for motor vehicle diesel fuel for the current compliance period and previous compliance periods.

(5) The volume balance required for purposes of compliance with § 80.598(b)(9)(vii)(B) means:

$-MVB \leq 0.02 \times MV_I$

(6) Calculations in paragraphs (b)(4) and (b)(5) of this section may be combined for all facilities wholly owned by an entity.

(7) For purposes of calculations in paragraphs (b)(1) through (b)(5) of this section, for batches of fuel received from facilities without an EPA facility ID#, any batches of fuel received on which taxes have been paid pursuant to IRS code (26 CFR part 48) shall be deemed to be $MV15_I$ or $MV500_I$ as appropriate for purposes of this paragraph.

(c) *Volume balance for high sulfur NRLM diesel fuel and heating oil.* (1) A facility's high sulfur NRLM balance is calculated as follows:

$HSNRLMB = HSNRLMI_I - HSNRLM_O - HSNRLM_{INVCHG}$

Where:

HSNRLMB = the balance for high sulfur NRLM diesel fuel for the compliance period.

$HSNRLM_I$ = the total volume of all batches of fuel designated as high sulfur NRLM received diesel fuel for the compliance period.

$HSNRLM_O$ = the total volume of all batches of fuel designated as high sulfur NRLM diesel fuel delivered for the compliance period.

$HSNRLM_{INVCHG}$ = the volume of high sulfur NRLM diesel fuel in inventory at the end of the compliance period minus the volume of high sulfur NRLM diesel fuel in inventory at the beginning of the compliance period, including accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

(2) The volume balance required for purposes of compliance with § 80.598(b)(9)(viii)(A) means one of the following:

(i) $HSNRLMB \geq 0$

(ii) $(HSNRLM_O + HSNRLM_{INVCHG}) / HSNRLM_I \leq (HO_O + HO_{INVCHG}) / HO_I$

(3) A facility's heating oil volume balance is calculated as follows:

$HOB = HO_I - HO_O - HO_{INVCHG}$

Where:

HOB = the balance for heating oil for the compliance period.

HO_I = the total volume of all batches of fuel designated as heating oil received for the compliance period.

HO_O = the total volume of all batches of fuel designated as heating oil delivered to all downstream entities for the compliance period.

HO_{INVCHG} = the volume of heating oil in inventory at the end of the compliance period minus the volume of heating oil in inventory at the beginning of the compliance period, including accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

(4) The volume balance required for purposes of compliance with § 80.598(b)(9)(viii)(B) means:

$HOB \leq 0$

(5) Calculations in paragraphs (c)(3) and (c)(4) of this section may be combined for all facilities wholly owned by an entity.

(6) For purposes of calculations in paragraphs (c)(1) through (c)(4) of this section, for batches of fuel received from facilities without an EPA facility ID#, any batches of fuel received marked pursuant to § 80.510(d) or (f) shall be deemed to be HO_I, any batches of fuel received marked pursuant to § 80.510(e) shall be deemed to be HO_I or $LM500_I$, any diesel fuel with less than or equal to 500 ppm sulfur that is dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(d) or (f) shall be deemed to be NRLM diesel fuel, and any diesel fuel with less than or equal to 500 ppm sulfur which is dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(e) shall be deemed to be NR diesel fuel.

(d) *Volume balance for NR diesel fuel.* (1) A facility's 500 ppm nonroad diesel fuel balance is calculated as follows:

$NR500B = NR500_I - NR500_O - NR500_{INVCHG}$

Where:

NR500B = the balance for 500 ppm sulfur NR diesel fuel for the compliance period.

$NR500_I$ = the total volume of all batches of fuel designated as 500 ppm sulfur NR diesel fuel received for the compliance period.

$NR500_O$ = the total volume of all batches of fuel designated as 500 ppm sulfur NR diesel fuel delivered for the compliance period.

$NR500_{INVCHG}$ = the volume of 500 ppm sulfur NR diesel fuel in inventory at the end of the compliance period minus the volume of 500 ppm sulfur NR diesel fuel in inventory at the beginning of the compliance period, and accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

(2) The volume balance required for purposes of compliance with § 80.598(b)(9)(ix) means one of the following:

(i) $NR500B \geq 0$

(ii) $(NR500_O + NR500_{INVCHG}) / NR500_I \leq (LM500_O + LM500_{INVCHG}) / LM500_I$

Where:

$LM500_I$ = the total volume of all batches of fuel designated as 500 ppm sulfur LM diesel fuel received for the compliance period.

$LM500_O$ = the total volume of all batches of fuel designated as 500 ppm sulfur LM diesel fuel delivered for the compliance period.

$LM500_{INVCHG}$ = the volume of 500 ppm sulfur LM diesel fuel in inventory at the end of the compliance period minus the volume of 500 ppm sulfur LM diesel fuel in inventory at the beginning of the compliance period, and accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

(e) *Anti-downgrading for motor vehicle diesel fuel.* (1) A facility must satisfy the provisions in either paragraphs (e)(2), (e)(3), (e)(4), or (e)(5) of this section to comply with the anti-downgrading limitation of paragraph § 80.527(c)(1), for the annual compliance periods defined in § 80.527(c)(3).

(2) The volume of #2D 15 ppm sulfur motor vehicle delivered must meet the following requirement:

$(\#2MV15_O + \#2MV15_{INVCHG}) \geq 0.8 \times \#2MV15_I$

Where:

$\#2MV15_O$ = the total volume of fuel delivered during the compliance period that is designated as #2D 15 ppm sulfur motor vehicle diesel fuel.

$\#2MV15_{INVCHG}$ = the total volume of diesel fuel designated as #2D 15 ppm sulfur motor vehicle diesel fuel in inventory at the end of the compliance period minus the total volume of #2D 15 ppm sulfur motor vehicle diesel fuel in inventory at the beginning of the compliance period, and accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

$\#2MV15_I$ = the total volume of fuel received during the compliance period that is designated as #2D 15 ppm sulfur motor vehicle diesel fuel.

(3) The volume of #2D 500 ppm sulfur motor vehicle diesel fuel delivered must meet the following requirement:

$\#2MV500_O \leq \#2MV500_I - \#2MV500_{INVCHG} + 0.2 \times \#2MV15_I$

Where:

$\#2MV500_O$ = the total volume of fuel delivered during the compliance period that is designated as #2D 500 ppm sulfur motor vehicle diesel fuel.

$\#2MV500_I$ = the total volume of fuel received during the compliance period that is designated as #2D 500 ppm sulfur motor vehicle diesel fuel.

$\#2MV500_{INVCHG}$ = the total volume of diesel fuel designated as #2D 500 ppm sulfur motor vehicle diesel fuel in inventory at the end of the compliance period minus the total volume of #2D 500 ppm sulfur motor vehicle diesel fuel in inventory at the beginning of the compliance period, and accounting for any corrections in inventory due to volume swell or shrinkage, difference in measurement calibration between receiving and delivering meters, and similar matters, where corrections that increase inventory are defined as positive.

(4) The following calculation may be used to account for wintertime blending of kerosene:

$\#2MV500_O \leq \#2MV500_I - \#2MV500_{INVCHG} + 0.2 * (\#1MV15_I + \#2MV15_I)$

Where:

$\#1MV15_I$ = the total volume of fuel received during the compliance period that is designated as #1D 15 ppm sulfur motor vehicle diesel fuel.

(5) The following calculation may be used to account for wintertime blending of kerosene and/or changes in the facility's volume balance of motor vehicle diesel fuel resulting from a temporary shift of 500 ppm sulfur NRLM diesel fuel to 500 ppm sulfur motor vehicle diesel fuel during the compliance period:

$\#2MV500_O < \#2MV500_I - \#2MV500_{INVCHG} + 0.2 * \#2MV15_I + \#1MV15_B + \#2NRLM500_S$

Where:

$\#1MV15_B$ = the total volume of fuel received during the compliance period that is designated as #1D 15 ppm sulfur motor vehicle diesel fuel and that the facility can demonstrate they blended into #2D 500 ppm sulfur motor vehicle diesel fuel.

$\#2NRLM500_S$ = the total volume of #2D 500 ppm sulfur NRLM diesel fuel that the facility can demonstrate they redesignated as #2D 500 ppm sulfur motor vehicle diesel fuel during the compliance period.

(f) *Inventory adjustments.* Adjustments to inventory under this section must be based on normal business practices for the industry, appropriate physical plant operations and use of good engineering judgments.

(g) *Unique circumstances.* EPA may, at its discretion, grant a fuel distributor's application to modify its inventory of motor vehicle diesel fuel, NRLM diesel fuel, or heating oil for a given compliance period. EPA may grant an application to address unique circumstances, where appropriate, such as the start up of a new pipeline or pipeline segment.

■ 57. The center header "EXEMPTIONS" before § 80.600 is removed.

■ 58. Section 80.600 is revised to read as follows:

§ 80.600 What records must be kept for purposes of the designate and track provisions?

(a) In addition to the requirements of § 80.592 and § 80.602, the following recordkeeping requirements shall apply to refiners and importers:

(1) Any refiner or importer shall maintain the records specified in paragraphs (a)(6) through (a)(10) of this section for each batch of distillate fuel that it transfers custody of and designates during the time period from June 1, 2006 through May 31, 2010, with the following categories:

(i) #1D 15 ppm sulfur motor vehicle diesel fuel;

(ii) #2D 15 ppm sulfur motor vehicle diesel fuel;

(iii) 15 ppm sulfur NRLM diesel fuel;

(iv) #1D 500 ppm sulfur motor vehicle diesel fuel;

(v) #2D 500 ppm sulfur motor vehicle diesel fuel; or

(vi) 500 ppm sulfur NRLM diesel fuel.

(2) Any refiner or importer shall maintain the records specified in paragraphs (a)(6) through (a)(10) of this section for each batch of distillate fuel that it transfers custody of and designates during the time period from June 1, 2007 through May 31, 2010 with the following categories:

(i) High sulfur NRLM diesel fuel; or

(ii) Heating oil.

(3) Any refiner or importer shall maintain the records specified in paragraphs (a)(6) through (a)(10) of this section for each batch of distillate fuel that it transfers custody of and designates during the time period from June 1, 2010 through May 31, 2012 with the following categories:

(i) 500 ppm sulfur NR diesel fuel;

(ii) 500 ppm sulfur LM diesel fuel; or

(iii) Heating oil.

(4) Any refiner or importer shall maintain the records specified in paragraphs (a)(6) through (a)(10) of this section for each batch of distillate fuel that it transfers custody of and designates during the time period from June 1, 2012 through May 31, 2014 with the following categories:

(i) 500 ppm sulfur NRLM diesel fuel; or

(ii) Heating oil.

(5) Any refiner or importer shall maintain the records specified in paragraphs (a)(6) through (a)(10) of this section for each batch of heating oil that it transfers custody of and designates during the time period from June 1, 2014 and later as belonging to the heating oil category.

(6) The records for each batch with designations identified in paragraphs (a)(1) through (a)(5) of this section must clearly and accurately identify the batch number (including an indication as to whether the batch was received into the facility or delivered from the facility), date and time of day (if multiple batches are delivered per day) that custody was transferred, the designation, the volume in gallons of the batch, and the name and the EPA entity and facility registration number of the facility to whom such batch was transferred.

(i) For motor vehicle diesel fuel, the records must also identify whether the batch was received or delivered with or without taxes paid pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082).

(ii) For NRLM diesel fuel, the records must also identify whether the batch was received or delivered with or without dye added pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082).

(iii) For heating oil, the records must also identify whether the batch was received or delivered with or without the marker added pursuant to § 80.510(d) through (f).

(iv) For LM diesel, the records must also identify whether the batch was received or delivered with or without the marker added pursuant to § 80.510(e).

(7) Any refiner or importer shall, for each of its facilities, maintain records that clearly and accurately identify the total volume in gallons of designated fuel identified in paragraphs (a)(1) through (a)(5) of this section transferred over each compliance period. The records shall be maintained separately for each fuel designated in paragraphs (a)(1) through (a)(5) of this section, and for each EPA entity and facility registration number to whom custody of the fuel was transferred.

(8) Notwithstanding the provisions of paragraphs (a)(6) and (a)(7) of this section, records of batches delivered of 500 ppm sulfur motor vehicle diesel fuel on which taxes have been paid per Section 4082 of the Internal Revenue Code (26 U.S.C. 4082) and of 500 ppm sulfur NRLM diesel fuel into which dye has been added per Section 4082 of the Internal Revenue Code (26 U.S.C. 4082), and of 500 ppm sulfur LM diesel fuel which has been properly marked pursuant to § 80.510(e) are not required to be maintained separately for each entity and facility to which the fuel was delivered.

(9) Notwithstanding the provisions of paragraphs (a)(6) and (a)(7) of this section, records of heating oil batches delivered that have been properly marked pursuant to § 80.510(d) through (f) and records of LM diesel fuel batches delivered that have been properly marked pursuant to § 80.510(e) are not required to be maintained separately for each entity and facility to which the fuel was delivered.

(10) Any refiner or importer shall maintain copies of all product transfer documents required under § 80.590. If all information required in paragraph (a)(6) of this section is on the product transfer document for a batch, then the provisions of this paragraph (a)(10) shall satisfy the requirements of paragraph (a)(6) of this section for that batch.

(11) Any refiner or importer shall maintain records related to annual compliance calculations performed under § 80.599 and to information required to be reported to the Administrator under § 80.601.

(12) Records must be maintained that demonstrate compliance with a refiner's compliance plan required under § 80.554, for distillate fuel designated as high sulfur NRLM diesel fuel and delivered from June 1, 2007 through May 31, 2010, for distillate fuel designated as 500 ppm sulfur NR diesel fuel and delivered from June 1, 2010 through May 31, 2012, and for distillate fuel designated as 500 ppm sulfur NRLM diesel fuel and delivered from June 1, 2012 through June 1, 2014 in the areas specified in § 80.510(g)(2).

(b) In addition to the requirements of § 80.592 and § 80.602, the following recordkeeping requirements shall apply to distributors:

(1) Any distributor shall maintain the records specified in paragraphs (b)(2) through (b)(10) of this section for each batch of distillate fuel with the following designations for which custody is received or delivered. Records shall be kept separately for each of its facilities.

(i) For each facility that receives #2D 15 ppm sulfur motor vehicle diesel fuel and distributes any #2D 500 ppm sulfur motor vehicle diesel fuel, records for each batch of diesel fuel with the following designations for which custody is received or delivered during the time period from June 1, 2006 through May 31, 2007:

(A) #1D 15 ppm sulfur motor vehicle diesel fuel;

(B) #2D 15 ppm sulfur motor vehicle diesel fuel;

(C) #2D 500 ppm sulfur motor vehicle diesel fuel; or

(D) 500 ppm sulfur NRLM diesel fuel.

(ii) For each facility, records for each batch of diesel fuel with the following designations for which custody is received or delivered during the time period from June 1, 2007 through May 31, 2010:

(A) #1D 15 ppm sulfur motor vehicle diesel fuel;

(B) #2D 15 ppm sulfur motor vehicle diesel fuel;

(C) #1D 500 ppm sulfur motor vehicle diesel fuel;

(D) #2D 500 ppm sulfur motor vehicle diesel fuel;

(E) 500 ppm sulfur NRLM diesel fuel;

(F) 15 ppm sulfur NRLM diesel fuel;

(G) High sulfur NRLM diesel fuel; or

(H) Heating oil.

(iii) For each facility that receives unmarked fuel designated as NR diesel fuel, LM diesel fuel or heating oil, records for each batch of diesel fuel with the following designations for which custody is received or delivered during the time period from June 1, 2010 through May 31, 2012:

(A) 500 ppm sulfur NR diesel fuel;

(B) 500 ppm sulfur LM diesel fuel; or

(C) Heating oil.

(iv) For each facility that receives unmarked fuel designated as heating oil, records for each batch of diesel fuel with the following designations for which custody is received or delivered during the time period from June 1, 2012 through May 31, 2014:

(A) 500 ppm sulfur NRLM diesel fuel; or

(B) Heating oil.

(v) For each facility that receives unmarked fuel designated as heating oil, records for each batch of diesel fuel with the following designations for which custody is received or delivered during the time period beginning June 1, 2014:

(A) 500 ppm sulfur LM diesel fuel; or

(B) Heating oil.

(vi) From June 1, 2007 through May 31, 2010, for those facilities in the areas specified in § 80.510(g)(2) that receive unmarked fuel designated as high sulfur NRLM diesel fuel:

(A) High sulfur NRLM diesel fuel; or

(B) Heating oil.

(vii) From June 1, 2010 through May 31, 2012, for those facilities in the areas specified in § 80.510(g)(2) that receive unmarked fuel designated as 500 ppm sulfur NR diesel fuel, 500 ppm sulfur LM diesel fuel, or heating oil:

(A) 500 ppm sulfur NR diesel fuel;

(B) 500 ppm sulfur LM diesel fuel; or

(C) Heating oil.

(viii) From June 1, 2012 through May 31, 2014, for those facilities in the areas specified in § 80.510(g)(2) that receive unmarked fuel designated as 500 ppm sulfur NRLM diesel fuel or heating oil.

(A) 500 ppm sulfur NRLM diesel fuel; or

(B) Heating oil.

(2) Records that for each batch clearly and accurately identify the batch number (including an indication as to whether the batch was received into the facility or delivered from the facility), date and time of day (if multiple batches are delivered per day) that custody was transferred, the designation, the volume in gallons of each batch of each fuel, and the name and the EPA entity and facility registration number of the facility to whom or from whom such batch was transferred.

(i) For motor vehicle diesel fuel the records must also identify whether the batch was received or delivered with or without taxes paid pursuant to section 4082 of the Internal Revenue Code (26 U.S.C. 4082).

(ii) For NRLM diesel fuel, the records must also identify whether it was received or delivered with or without dye added pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082).

(iii) For heating oil, the records must also identify whether it was received or delivered with or without the marker added pursuant to § 80.510(d) through (f).

(iv) For LM diesel fuel, the records must also identify whether it was received or delivered with or without the marker added pursuant to § 80.510(e).

(v) For batches of fuel received from facilities without an EPA facility registration number, any batches of fuel received marked pursuant to § 80.510(d) or (f) shall be deemed designated as heating oil, any batches of fuel received marked pursuant to § 80.510(e) shall be deemed designated as heating oil or LM diesel fuel, any batches of fuel received on which taxes have been paid pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082) shall be deemed designated as motor vehicle diesel fuel, any 500 ppm sulfur diesel fuel dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(d) or (f) shall be deemed designated as NRLM diesel fuel, and any diesel fuel with less than or equal to 500 ppm sulfur which is dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(e) shall be deemed to be NR diesel fuel.

(3) Records that clearly and accurately identify the total volume in gallons of each designated fuel identified under paragraph (b)(1) of this section transferred over each of the compliance periods, and over the periods from June 1, 2007 to the end of each compliance period. The records shall be maintained separately for each fuel designated under paragraph (b)(1) of this section, and for each EPA entity and facility registration number from whom the fuel was received or to whom it was delivered. For batches of fuel received from facilities without an EPA facility registration number, any batches of fuel received marked pursuant to § 80.510(d) or (f) shall be deemed designated as heating oil, any batches of fuel received marked pursuant to § 80.510(e) shall be deemed designated as heating oil or LM diesel fuel, any batches of fuel received on which taxes have been paid pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082) shall be deemed designated as motor vehicle diesel fuel, any 500 ppm sulfur diesel fuel dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(d) or (f) shall be deemed designated as NRLM diesel fuel, and any diesel fuel with less than or equal to 500 ppm sulfur which is dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(e) shall be deemed to be NR diesel fuel.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (b)(3) of this section, for batches of 500 ppm sulfur motor vehicle diesel fuel delivered on which taxes have been paid per Section 4082 of the Internal Revenue Code (26 U.S.C. 4082) and 500 ppm sulfur NRLM diesel fuel into which red dye has been added per Section 4082 of the Internal Revenue Code (26 U.S.C. 4082), records are not required to be maintained separately for each entity or facility to whom fuel was delivered.

(5) Notwithstanding the provisions of paragraphs (b)(2) and (b)(3) of this section, for batches of heating oil delivered that are marked pursuant to § 80.510(d) through (f), records do not need to identify the EPA entity or facility registration number to which fuel was delivered.

(6) Notwithstanding the provisions of paragraphs (b)(2) and (b)(3) of this section, for batches of LM diesel fuel delivered that are marked pursuant to § 80.510(e), records do not need to identify the EPA entity or facility registration number to which fuel was delivered.

(7) Records that clearly and accurately reflect the beginning and ending inventory volume for each of the fuels for which records must be kept under paragraph (b)(1) of this section. Such records shall be maintained separately by each entity and facility consistent with the compliance periods defined in §§ 80.598 and 80.599.

(8) (i) If adjustments are made to inventory, the records must include detailed information related to the amount, type of, and reason for such adjustment.

(ii) If adjustments are made because of measurement error or variation, the records must include the adjustment made, the meter or gauge or other reading(s), and the name of the person who took such reading(s) and or applied the adjustment.

(9) For distributors that are required to keep records under paragraphs (b)(1) through (b)(8) of this section for truck loading terminals, records related to quarterly or annual compliance calculations, as applicable, performed under § 80.599 and to information required to be reported to the Administrator under § 80.601.

(10) For distributors that are required to keep records under paragraphs (b)(1) through (b)(8) of this section for facilities other than truck loading terminals, records related to annual compliance calculations performed under § 80.599 and to information required to be reported to the Administrator under § 80.601.

(c) Notwithstanding the provisions of paragraph (b) of this section, records of heating oil received are not required to be maintained for facilities that do not receive any heating oil which is unmarked pursuant to § 80.510(d) through (f), or LM diesel fuel which is unmarked pursuant to § 80.510(e).

(d) Notwithstanding the provisions of paragraph (b) of this section, records of 500 ppm sulfur MVNRLM diesel fuel received are not required to be maintained for facilities that do not receive any motor vehicle diesel fuel for which taxes have not already been paid pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082) or NRLM diesel fuel which is undyed pursuant to § 80.520(b).

(e) The provisions of paragraphs (b)(1)(iii) and (iv) of this section do not apply to facilities located in the areas specified in § 80.510(g)(1) and (g)(2) unless they deliver marked heating oil or LM diesel fuel to areas outside the areas specified in § 80.510(g)(1) and (g)(2).

(f) Ultimate consumers that receive any batch of high sulfur NRLM diesel fuel beginning June 1, 2007 in areas listed in § 80.510(g)(2) must maintain records of each batch of fuel received for use in NRLM equipment pursuant to the compliance plan provisions of § 80.554, unless otherwise allowed by EPA.

(g) Ultimate consumers that receive any batch of 500 ppm sulfur NR diesel fuel beginning June 1, 2010 or NRLM diesel fuel beginning June 1, 2012 in the areas listed in § 80.510(g)(2) must maintain records of each batch of fuel received for use in NR or NRLM equipment, as appropriate, pursuant to the compliance plan provisions of § 80.554, unless otherwise allowed by EPA.

(h) For purposes of this section, each portion of a shipment of designated distillate fuel under this section that is differently designated from any other portion, even if shipped as fungible product having the same sulfur content, shall be a separate batch.

(i) The records required in this section must be made available to the Administrator or the Administrator's designated representative upon request.

(j) Notwithstanding the provisions of this section, product transfer documents must be maintained under the provisions of §§ 80.590, 80.592, and 80.602.

(k) The records required in this section must be kept for five years after they are required to be collected.

(l) Identifications of fuel designations can be limited to a sub-designation that accurately identifies the fuel and do not need to also include the broader designation. For example, NR diesel fuel does not also need to be designated as NRLM or MVNRLM diesel fuel.

■ 59. Section 80.601 is revised to read as follows:

§ 80.601 What are the reporting requirements for purposes of the designate and track provisions?

(a) *Quarterly reporting.* Beginning November 30, 2007 and continuing through August 31, 2010, each entity required to maintain records under § 80.600 must report the following information separately for each of its facilities to the Administrator on a quarterly basis, as specified in paragraph (e)(1) of this section:

(1) Separately for each designation category and separately for each transferee facility, the total volume in gallons of distillate fuel designated under § 80.598 for which custody was delivered by the reporting facility to any other entity or facility, and the EPA entity and facility registration number(s), as applicable, of the transferee.

(2) Separately for each designation category and separately for each transferor facility, the total volume in gallons of distillate fuel designated under § 80.598 for which custody was received by the reporting facility, and the EPA entity and facility registration number(s), as applicable, of the transferor.

(3) Any entity that receives custody of distillate fuel from another entity or facility that does not have an EPA facility identification number must report such batches as follows:

(i) Any batch of distillate fuel for which custody is received and which is marked pursuant to § 80.510(d) or (f) shall be deemed designated as heating oil, any batch of distillate fuel for which custody is received and which is marked pursuant to § 80.510(e) shall be deemed designated as heating oil or LM diesel fuel as applicable, and the report shall include that information under that designation.

(ii) Any batch of distillate fuel for which custody is received and for which taxes have been paid pursuant to Section 4082 of the Internal Revenue Code (26 U.S.C. 4082) shall be deemed designated as motor vehicle diesel fuel and the report shall include it under that designation.

(iii) Any batch of 500 ppm sulfur diesel fuel dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(d) and (f), and for which custody is received, shall be deemed designated as NRLM diesel fuel and the report shall include it under that designation.

(iv) Any batch of 500 ppm sulfur diesel fuel dyed pursuant to § 80.520(b) and not marked pursuant to § 80.510(e), and for which custody is received, shall be deemed designated as NR diesel fuel and the report shall include it under that designation.

(4) In the case of truck loading terminals, the results of all compliance calculations required under § 80.599, and including:

(i) The total volumes received of each fuel designation required to be reported in paragraphs (a)(1) through (a)(3) of this section over the quarterly compliance period.

(ii) The total volumes delivered of each fuel designation required to be reported in paragraphs (a)(1) through (a)(3) of this section over the quarterly compliance period.

(iii) Beginning and ending inventories of each fuel designation required to be reported in paragraphs (a)(1) through(a)(3) of this section over the quarterly compliance period.

(iv) The volume balance under § 80.599(b)(4) and § 80.598(b)(9)(vi).

(v) The volume balance under § 80.599(c)(2) and § 80.598(b)(9)(viii)(A).

(b) *Annual reports.* Beginning August 31, 2007, all entities required to maintain records for batches of fuel under § 80.600 must report the following information separately for each of its facilities to the Administrator on an annual basis, as specified in paragraph (e)(2) of this section:

(1) Separately for each designation category for which records are required to be kept under § 80.600 and separately for each transferor facility, the total volume in gallons of distillate fuel designated under § 80.598 for which custody was received by the reporting

facility, and the EPA entity and facility registration number(s), as applicable, of the transferor.

(2) Separately for each designation category for which records are required to be kept under § 80.600 and separately for each transferee facility, the total volume in gallons of distillate fuel designated under § 80.598 for which custody was delivered by the reporting facility to any other entity or facility, and the EPA entity and facility registration number(s), as applicable, of the transferee except as provided under § 80.600(a)(7), (a)(8), (b)(4), and (b)(5):

(3) The results of all compliance calculations required under § 80.599, and including:

(i) The total volumes in gallons received of each fuel designation required to be reported in paragraph (b)(1) of this section over the applicable annual compliance period.

(ii) The total volumes in gallons delivered of each fuel designation required to be reported in paragraph (b)(2) of this section over the applicable annual compliance period.

(iii) Beginning and ending inventories of each fuel designation required to be reported in paragraphs (b)(1) and (b)(2) of this section for the annual compliance period.

(iv) In the areas specified in § 80.510(g)(2), for fuel designated as high sulfur NRLM diesel fuel delivered from June 1, 2007 through May 31, 2010, for fuel designated as 500 ppm NR diesel fuel delivered from June 1, 2010 through May 31, 2012, and for fuel designated as 500 ppm sulfur NRLM diesel fuel from June 1, 2012 through May 31, 2014, the refiner must report all information required under its compliance plan approved pursuant to § 80.554(a)(4) and (b)(4) and including the ultimate consumers to whom each batch of fuel was delivered and the total delivered to each ultimate consumer for the compliance period.

(v) Ending with the report due August 31, 2010, the volume balance under § 80.598(b)(9)(vi) and § 80.599(b)(4).

(vi) Ending with the report due August 31, 2010, the volume balance under § 80.598(b)(9)(vii) and § 80.599(b)(5), if applicable.

(vii) Ending with the report due August 31, 2010, the volume balance under § 80.598(b)(9)(viii)(A) and § 80.599(c)(2).

(viii) Beginning with the report due August 31, 2010, the volume balance under § 80.598(b)(8)(viii)(B) and § 80.599(c)(4).

(ix) Beginning with the report due August 1, 2011 and ending with the report due August 1, 2012, the volume balance under § 80.598(b)(9)(ix) and § 80.599(d)(2).

(c) *Additional information.* The Administrator may request any additional information necessary to determine compliance with the requirements of §§ 80.598 and 80.599.

(d) *Submission of quarterly and annual reports.* (1) All quarterly reports shall be submitted to the Administrator for the compliance periods defined in § 80.599(a)(1) as follows:

(i) The first quarter report shall be submitted by the following November 30.

(ii) The second quarter report shall be submitted by the following February 28.

(iii) The third quarter report shall be submitted by the following May 31.

(iv) The fourth quarter report shall be submitted by the following August 31.

(2) All annual reports shall be submitted to the Administrator for the compliance periods defined in § 80.599(a)(2) by August 31.

(3) All reports shall be submitted on forms and following procedures specified by the Administrator, shall include a statement that volumes reported to the Administrator under this section are identical to volumes reported to the Internal Revenue Service and shall be signed and certified by a responsible corporate officer of the reporting entity.

(e) *Exclusions.* Notwithstanding the provisions of this section, an entity is not required to report under paragraphs (a) or (b) of this section for facilities whose only recordkeeping requirements under § 80.600 are under § 80.600 (f) or (g) or to maintain records solely related to calculating compliance with the downgrading limitation under § 80.527, § 80.599(e) and § 80.600(b)(1)(i) and (ii).

■ 60. Section 80.602 is revised to read as follows:

§ 80.602 What records must be kept by entities in the NRLM diesel fuel and diesel fuel additive production, importation, and distribution systems?

(a) *Records that must be kept by parties in the NRLM diesel fuel and diesel fuel additive production, importation, and distribution systems.* Beginning June 1, 2007, or June 1, 2006, if that is the first period credits are generated under § 80.535, any person who produces, imports, sells, offers for sale, dispenses, distributes, supplies, offers for supply, stores, or transports nonroad, locomotive or marine diesel fuel subject to the provisions of this subpart, must keep the following records:

(1) The applicable product transfer documents required under §§ 80.590 and 80.591.

(2) For any sampling and testing for sulfur content for a batch of NRLM diesel fuel produced or imported and subject to the 15 ppm sulfur standard or any sampling and testing for sulfur content as part of a quality assurance testing program, and any sampling and testing for cetane index, aromatics content, marker solvent yellow 124 content or dye solvent red 164 content of NRLM diesel fuel, NRLM diesel fuel additives or heating oil:

(i) The location, date, time and storage tank or truck identification for each sample collected;

(ii) The name and title of the person who collected the sample and the person who performed the testing; and

(iii) The results of the tests for sulfur content (including where applicable the test results with and without application of the adjustment factor under § 80.580(a)(4)), for cetane index or aromatics content, dye solvent red 164, marker solvent yellow 124 (as applicable), and the volume of product in the storage tank or container from which the sample was taken.

(3) The actions the party has taken, if any, to stop the sale or distribution of any NRLM diesel fuel found not to be in compliance with the sulfur standards specified in this subpart, and the actions the party has taken, if any, to identify the cause of any noncompliance and prevent future instances of noncompliance.

(b) *Additional records to be kept by refiners and importers of NRLM diesel fuel.* Beginning June 1, 2007, or June 1, 2006, pursuant to the provisions of § 80.535 or § 80.554(d), any refiner producing diesel fuel subject to a sulfur standard under § 80.510, § 80.513, § 80.536, § 80.554, § 80.660, or § 80.561, for each of its refineries, and any importer importing such diesel fuel separately for each facility, shall keep records that include the following information for each batch of NRLM diesel fuel or heating oil produced or imported:

(1) The batch volume.

(2) The batch number, assigned under the batch numbering procedures under § 80.65(d)(3).

(3) The date of production or import.

(4) A record designating the batch as one of the following:

(i) NRLM diesel fuel, NR diesel fuel, LM diesel fuel, or heating oil, as applicable.

(ii) Meeting the 500 ppm sulfur standard of § 80.510(a) or the 15 ppm sulfur standard of § 80.510(b) and (c) or other applicable standard.

(iii) Dyed or undyed with visible evidence of solvent red 164.

(iv) Marked or unmarked with solvent yellow 124.

(5) For foreign refiners and importers of their fuel, the designations and other records required to be kept under § 80.620.

(6) All of the following information regarding credits, kept separately for each compliance period, kept separately for each refinery and for each importer facility, kept separately if converted under § 80.535(a) and (b) or § 80.535(c) and (d), and kept separately from motor vehicle diesel fuel credits:

(i) The number of credits in the refiner's or importer's possession at the beginning of the calendar year.

(ii) The number of credits generated.

(iii) The number of credits used.

(iv) If any were obtained from or transferred to other parties, for each other party, its name, its EPA refiner or importer registration number consistent with § 80.597, and the number obtained from, or transferred to, the other party.

(v) The number in the refiner's or importer's possession that will carry over into the subsequent calendar year compliance period.

(vi) Commercial documents that establish each transfer of credits from the transferor to the transferee.

(7) The calculations used to determine baselines or compliance with the volume requirements and volume percentages, as applicable, under this subpart.

(8) The calculations used to determine the number of credits generated.

(9) A copy of reports submitted to EPA under § 80.604.

(c) *Additional records importers must keep.* Any importer shall keep records that identify and verify the source of each batch of certified DFR-Diesel and non-certified DFR-Diesel imported and demonstrate compliance with the requirements under § 80.620.

(d) *Length of time records must be kept.* The records required in this section shall be kept for five years from the date they were created, except that records relating to credit transfers shall be kept by the transferor for five years from the date the credits were transferred, and shall be kept by the transferee for five years from the date the credits were transferred, used or terminated, whichever is later.

(e) *Make records available to EPA.* On request by EPA, the records required in this section must be made available to the Administrator or the Administrator's representative. For records that are electronically generated or maintained, the equipment and software necessary to read the records shall be made available, or if requested by EPA, electronic records shall be converted to paper documents which shall be provided to the Administrator's authorized representative.

■ 61. A new § 80.603 is added to read as follows:

§ 80.603 What are the pre-compliance reporting requirements for NRLM diesel fuel?

(a) Except as provided in paragraph (c) of this section, beginning on June 1, 2005, and for each year until June 1, 2011, or until the entity produces or imports NR or NRLM diesel fuel meeting the 15 ppm sulfur standard of § 80.510(b) or (c), all refiners and importers planning to produce or import NR or NRLM diesel fuel, shall submit the following information to EPA:

(1) Any changes to the information submitted for the company registration;

(2) Any changes to the information submitted for any refinery or import facility registration;

(3) Any estimate of the average daily volumes (in gallons) of each sulfur grade of motor vehicle and NRLM diesel fuel produced (or imported) at each refinery (or import facility). These volume estimates must be provided both for fuel produced from crude oil, as well as any fuel produced from other sources, and must be provided for the periods of June 1, 2010 through December 31, 2010, calendar years 2011 through 2013, January 1, 2014 through May 31, 2014, and June 1, 2014 through December 31, 2014;

(4) If expecting to participate in the credit trading program, estimates of the number of credits to be generated and/or used each year the program;

(5) Information on project schedule by quarter of known or projected completion date by the stage of the project, for example, following the five project phases described in EPA's June 2002 Highway Diesel Progress Review report (EPA420-R–02–016, *http://www.epa.gov/otaq/regs/hd2007/420r02016.pdf*): Strategic planning, Planning and front-end engineering, Detailed engineering and permitting, Procurement and construction, and Commissioning and startup:

(6) Basic information regarding the selected technology pathway for compliance (*e.g.*, conventional hydrotreating vs. other technologies, revamp vs. grassroots, etc.);

(7) Whether capital commitments have been made or are projected to be made; and

(8) The pre-compliance reports due in 2006 and later years must provide an update of the progress in each of these areas.

(b) Reports under this section may be submitted in conjunction with reports submitted under § 80.594.

(c) The pre-compliance reporting requirements of this section do not apply to refineries subject to the provisions of § 80.513.

■ 62. A new § 80.604 is added to read as follows:

§ 80.604 What are the annual reporting requirements for refiners and importers of NRLM diesel fuel?

Beginning with the annual compliance period that begins June 1, 2007, or the first period during which credits are generated, transferred or used, or the first period during which NRLM diesel fuel or heating oil is produced under a small refiner compliance option under this subpart, whichever is earlier, any refiner or importer who produces or imports NRLM diesel fuel must submit annual compliance reports for each refinery and importer facility that contain the following information required, and such other information as EPA may require.

(a) *All refiners and importers.* (1) The refiner or importer's company name and the EPA company and facility identification number.

(2) If the refiner is a small refiner, a statement regarding to which small refiner option it is subject.

(b) *Small refiners.* (1) For each refinery of small refiners subject to the provisions of § 80.551(g) and § 80.554(a) for each compliance period from June 1, 2007 through May 31, 2010, report the following:

(i) The total volume of diesel fuel produced and designated as NRLM diesel fuel.

(ii) The volume of diesel fuel produced and designated as NRLM diesel fuel having a sulfur content less than or equal to the 500 ppm sulfur standard under § 80.510(a).

(iii) The total volume of diesel fuel produced and designated as NRLM diesel fuel having a sulfur content greater than the 500 ppm sulfur standard under § 80.510(a).

(iv) The total volume of heating oil produced.

(v) The baseline under § 80.554(a)(1).

(vi) The total volume of diesel fuel produced and designated as NRLM diesel fuel that is exempt from the 500 ppm sulfur standard of § 80.510(a).

(vii) The total volume, if any, of NRLM diesel fuel subject to the 500 ppm sulfur standard § 80.510(a) that had a sulfur content exceeding 500 ppm.

(2) For each refinery of small refiners subject to the provisions of § 80.551(g) and § 80.554(b), for each compliance period between June 1, 2010 and May 31, 2012, report the following:

(i) The total volume of diesel fuel produced and designated as NR diesel fuel.

(ii) The total volume of diesel fuel produced and designated as LM diesel fuel.

(iii) The total volume of diesel fuel produced and designated as NR diesel fuel subject to the 500 ppm sulfur standard under § 80.510(a).

(iv) The total volume of diesel fuel produced and designated as LM diesel fuel subject to the 500 ppm sulfur standard under § 80.510(a).

(v) The volume of diesel fuel produced and designated as NR diesel fuel having a sulfur content of 15 ppm or less.

(vi) The baseline under § 80.554(b)(1).

(vii) The total volume of NRLM diesel fuel produced that is eligible for the sulfur standard under § 80.510(a). (viii) The total volume, if any, of NRLM diesel fuel subject to the 15 ppm sulfur standard that had a sulfur content in excess of 15 ppm.

(3) For each refinery of small refiners subject to the provisions of § 80.551(g) and § 80.554(b), for each compliance period between June 1, 2012 and May 31, 2014, report the following:

(i) The total volume of diesel fuel produced and designated as NRLM diesel fuel.

(ii) The total volume diesel fuel produced and designated as NRLM diesel fuel subject to the 500 ppm sulfur standard under § 80.510(a).

(iii) The total volume of diesel fuel produced and designated as NRLM diesel fuel having a sulfur content less than or equal to the 15 ppm sulfur standard under § 80.510(c).

(iv) The baseline under § 80.554(b)(1).

(v) The total volume of NRLM diesel fuel produced that is eligible for the 500 ppm sulfur standard under § 80.510(a).

(vi) The total volume, if any, of NRLM diesel fuel subject to the 15 ppm sulfur standard that had a sulfur content in excess of 15 ppm.

(4) For each refinery of a small refiner that elects to produce NRLM diesel fuel subject to the 15 ppm sulfur standard of § 80.510(c) beginning June 1, 2006 under § 80.551(g) and § 80.554(d), for each compliance period report the following:

(i) The total volume of diesel fuel produced and designated as NRLM diesel fuel.

(ii) The total volume of diesel fuel produced and designated as NRLM diesel fuel having a sulfur content less than or equal to 15 ppm.

(iii) The percentages of NRLM diesel fuel produced and designated having a sulfur content less than or equal to 15 ppm under § 80.554(d)(1)(i) and (ii).

(iv) The deficit, if any, and the number of credits purchased, if any, to cover any deficit as provided in § 80.554(d)(3).

(v) A report of the small refiner's progress toward compliance with the gasoline standards under §§ 80.240 and 80.255.

(c) *Credit generation and use.* Information regarding the generation, use, transfer and retirement of credits, separately by refinery and import facility, including the following:

(1) The number of credits at the beginning of the compliance period.

(2) The number of credits generated.

(3) The number of credits used.

(4) If any credits were obtained from or transferred to other refineries or importers, for each other refinery or importer, the name, address, the EPA company identification number, and the number of credits obtained from or transferred to the other party.

(5) The number of credits retired.

(6) The credit balance at the beginning and end of the compliance period.

(d) *Batch reports.* For each batch of NRLM diesel fuel and heating oil (if applicable) produced or imported and delivered during the compliance periods under paragraph (b) of this section, include the following:

(1) The batch volume.

(2) The batch number assigned using the batch numbering conventions under § 80.65(d)(3) and the appropriate designation under § 80.598.

(3) The date of production or import.

(4) For each batch provide the information specified in paragraph (a)(1) of this section.

(5) The sulfur content and cetane and aromatics content of the fuel.

(6) Whether the batch was dyed with visible evidence of dye solvent red 164 before leaving the refinery or import facility or was undyed.

(7) Whether the batch was marked with marker solvent yellow 124 before leaving the refinery or import facility or was unmarked.

(e) *Additional reporting requirements for importers.* Importers of NRLM diesel fuel are subject to the following additional requirements:

(1) The reporting requirements under § 80.620, if applicable.

(2) Importers must exclude certified DFR–Diesel from calculations under this section.

(f) *Report submission.* Any report required by this section must be—

(1) On forms and following procedures specified by the Administrator of EPA;

(2) Signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the refiner or importer; and

(3) Except for small refiners subject to § 80.554(d), submitted to EPA no later than August 31 each year for the prior annual compliance period. Small refiners subject to the provisions of § 80.554(d), reports must be submitted August 31 for the previous reporting period.

(4) With the exception of reports required under paragraph (b)(3) of this section, no reports will be required under this section after August 31, 2014.

■ 63. A center heading is added after § 80.604 to read as follows:

Exemptions

■ 64. A new § 80.606 is added to read as follows:

§ 80.606 What national security exemption applies to distillate fuel?

(a) The motor vehicle diesel fuel standards of § 80.520(a)(1), (a)(2), and (c) and the nonroad, locomotive or marine diesel fuel standards of § 80.510(a), (b), and (c) do not apply to distillate fuel that is produced, imported, sold, offered for sale, supplied, offered for supply, stored, dispensed, or transported for use in—

(1) Tactical military motor vehicles or tactical military nonroad engines, vehicles or equipment, including locomotive and marine, having an EPA national security exemption from the motor vehicle emissions standards under 40 CFR 85.1708, or from the nonroad engine emission standards under 40 CFR part 89, 40 CFR part 92, 40 CFR part 94, or 40 CFR part 1068; and

(2) Tactical military motor vehicles or tactical military nonroad engines, vehicles or equipment, including locomotive and marine, that are not subject to a national security exemption from vehicle or engine emissions standards as described in paragraph (a)(1) of this section but, for national security purposes (for purposes of readiness for deployment oversees), need to be fueled on the same fuel as the vehicles, engines, or equipment for which EPA has granted such a national security exemption.

(b) The exempt fuel must meet the following conditions:

(1) It must be accompanied by product transfer documents as required under § 80.590;

(2) It must be segregated from non-exempt MVNRLM diesel fuel at all points in the distribution system;

(3) It must be dispensed from a fuel pump stand, fueling truck or tank that is labeled with the appropriate designation of the fuel, such as "JP–5" or "JP–8"; and

(4) It may not be used in any motor vehicles or nonroad engines, equipment or vehicles, including locomotive and marine, other than the vehicles, engines, and equipment referred to in paragraph (a) of this section.

■ 65. A new § 80.607 is added to read as follows:

§ 80.607 What are the requirements for obtaining an exemption for diesel fuel used for research, development or testing purposes?

(a) *Written request for a research and development exemption.* Any person may receive an exemption from the provisions of this subpart for diesel fuel used for research, development, or testing purposes by submitting the information listed in paragraph (c) of this section to:

Director, Transportation and Regional Programs Division (6406J), U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460 (postal mail); or

Director, Transportation and Regional Programs Division, U.S. Environmental Protection Agency, 1310 L Street, NW., 6th floor, Washington, DC 20005 (express mail/courier); and

Director, Air Enforcement Division (2242A), U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(b) *Criteria for a research and development exemption.* For a research and development exemption to be granted, the person requesting an exemption must—

(1) Demonstrate a purpose that constitutes an appropriate basis for exemption;

(2) Demonstrate that an exemption is necessary;

(3) Design a research and development program to be reasonable in scope; and

(4) Exercise a degree of control consistent with the purpose of the program and EPA's monitoring requirements.

(c) *Information required to be submitted.* To demonstrate each of the elements in paragraphs (b)(1) through (4) of this section, the person requesting an exemption must include the following information in the written request required under paragraph (a) of this section:

(1) A concise statement of the purpose of the program demonstrating that the program has an appropriate research and development purpose.

(2) An explanation of why the stated purpose of the program cannot be achieved in a practicable manner without performing one or more of the prohibited acts under this subpart.

(3) To demonstrate the reasonableness of the scope of the program:

(i) An estimate of the program's duration in time and, if appropriate, mileage;

(ii) An estimate of the maximum number of vehicles or engines involved in the program;

(iii) The manner in which the information on vehicles and engines used in the program will be recorded and made available to the Administrator upon request; and

(iv) The quantity of diesel fuel which does not comply with the requirements of §§ 80.520 and 80.521 for motor vehicle diesel fuel or § 80.510 for NRLM diesel fuel.

(4) With regard to control, a demonstration that the program affords EPA a monitoring capability, including the following:

(i) The site(s) of the program (including facility name, street address, city, county, state, and zip code);

(ii) The manner in which information on vehicles and engines used in the program will be recorded and made available to the Administrator upon request;

(iii) The manner in which information on the diesel fuel used in the program (including quantity, fuel properties, name, address, telephone number and contact person of the supplier, and the date received from the supplier), will be recorded and made available to the Administrator upon request;

(iv) The manner in which the party will ensure that the research and development fuel will be segregated from motor vehicle diesel fuel or NRLM diesel fuel, as applicable, and how fuel pumps will be labeled to ensure proper use of the research and development diesel fuel;

(v) The name, address, telephone number and title of the person(s) in the organization requesting an exemption from whom further information on the application may be obtained; and

(vi) The name, address, telephone number and title of the person(s) in the organization requesting an exemption who is responsible for recording and making available the information specified in this paragraph (c), and the location where such information will be maintained.

(d) *Additional requirements.* (1) The product transfer documents associated with research and development motor vehicle diesel fuel must comply with requirements of § 80.590(b)(3).

(2) The research and development diesel fuel must be designated by the refiner or supplier, as applicable, as research and development diesel fuel.

(3) The research and development diesel fuel must be kept segregated from non-exempt MVNRLM diesel fuel at all points in the distribution system.

(4) The research and development diesel fuel must not be sold, distributed, offered for sale or distribution, dispensed, supplied, offered for supply, transported to or from, or stored by a diesel fuel retail outlet, or by a wholesale purchaser-consumer facility, unless the wholesale purchaser-consumer facility is associated with the research and development program that uses the diesel fuel.

(5) At the completion of the program, any emission control systems or elements of design which are damaged or rendered inoperative shall be replaced on vehicles remaining in service, or the responsible person will be liable for a violation of the Clean Air Act section 203(a)(3) (42 U.S.C. 7522 (a)(3)) unless sufficient evidence is supplied that the emission controls or elements of design were not damaged.

(e) *Mechanism for granting of an exemption.* A request for a research and development exemption will be deemed approved by the earlier of 60 days from the date on which EPA receives the request for exemption, (provided that EPA has not notified the applicant of potential disapproval by that time), or the date on which the applicant receives a written approval letter from EPA.

(1) The volume of diesel fuel subject to the approval shall not exceed the estimated amount under paragraph (c)(3)(iv) of this section, unless EPA grants a greater amount in writing.

(2) Any exemption granted under this section will expire at the completion of the test program or three years from the date of approval, whichever occurs first, and may only be extended upon re-application consistent will all requirements of this section.

(3) The passage of 60 days will not signify the acceptance by EPA of the validity of the information in the request for an exemption. EPA may elect at any time to review the information contained in the request, and where appropriate may notify the responsible person of disapproval of the exemption.

(4) In granting an exemption the Administrator may include terms and conditions, including replacement of emission control devices or elements of design, that the Administrator determines are necessary for monitoring the exemption and for assuring that the purposes of this subpart are met.

(5) Any violation of a term or condition of the exemption, or of any requirement of this section, will cause the exemption to be void *ab initio.*

(6) If any information required under paragraph (c) of this section should change after approval of the exemption, the responsible person must notify EPA in writing immediately. Failure to do so may result in disapproval of the exemption or may make it void *ab initio,* and may make the party liable for a violation of this subpart.

(f) *Effects of exemption.* Motor vehicle diesel fuel or NRLM diesel fuel that is subject to a research and development exemption under this section is exempt from other provisions of this subpart provided that the fuel is used in a manner that complies with the purpose of the program under paragraph (c) of this section and the requirements of this section.

(g) *Notification of completion.* The party shall notify EPA in writing within 30 days after completion of the research and development program.

■ 66. A new § 80.608 is added to read as follows:

§ 80.608 What requirements apply to diesel fuel for use in the Territories?

The sulfur standards of § 80.520(a)(1) and (c) related to motor vehicle diesel fuel, and of § 80.510(a), (b), and (c) related to NRLM diesel fuel, do not apply to diesel fuel that is produced, imported, sold, offered for sale, supplied, offered for supply, stored, dispensed, or transported for use in the Territories of Guam, American Samoa or the Commonwealth of the Northern Mariana Islands, provided that such diesel fuel is—

(a) Designated by the refiner or importer as high sulfur diesel fuel only for use in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands;

(b) Used only in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands;

(c) Accompanied by documentation that complies with the product transfer document requirements of § 80.590(b)(1); and

(d) Segregated from non-exempt MVNRLM diesel fuel at all points in the distribution system from the point the diesel fuel is designated as exempt fuel only for use in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands, while the exempt fuel is in the United States but outside these Territories.

■ 67. Section 80.610 is revised to read as follows:

§ 80.610 What acts are prohibited under the diesel fuel sulfur program?

No person shall—

(a) *Standard, dye, marker or product violation.* (1) Produce, import, sell, offer for sale, dispense, supply, offer for supply, store or transport motor vehicle diesel fuel, NRLM diesel fuel, or heating oil that does not comply with the applicable standards, dye, marking or any other product requirements under this subpart I and 40 CFR part 69.

(2) Beginning June 1, 2007, produce, import, sell, offer for sale, dispense, supply, offer for supply, store or transport any diesel fuel for use in motor vehicle or nonroad engines that contains greater than 0.10 milligrams per liter of solvent yellow 124, except for 500 ppm sulfur diesel fuel produced or imported from June 1, 2010 through September 30, 2012 for use only in locomotive or marine diesel engines that is marked under the provisions of § 80.510(e).

(3) Beginning June 1, 2007, produce, import, sell, offer for sale, dispense, supply, offer for supply, store or transport heating oil for use in any nonroad diesel engine, including any locomotive or marine diesel engine.

(b) *Designation and volume balance violation.* Produce, import, sell, offer for sale, dispense, supply, offer for supply, store or transport motor vehicle diesel, NRLM diesel fuel, heating oil or other distillate that does not comply with the applicable designation or volume balance requirements under §§ 80.598 and 80.599.

(c) *Additive violation.* (1) Produce, import, sell, offer for sale, dispense, supply, offer for supply, store or transport any motor vehicle diesel fuel additive or NRLM diesel fuel additive for use at a downstream location that does not comply with the applicable requirements of § 80.521.

(2) Blend or permit the blending into motor vehicle diesel fuel or NRLM diesel fuel at a downstream location, or use, or permit the use, in motor vehicle diesel fuel or NRLM diesel fuel, of any additive that does not comply with the applicable requirements of § 80.521.

(d) *Used motor oil violation.* Introduce into the fuel system of a model year 2007 or later diesel motor vehicle or model year 2011 or later nonroad diesel engine (except for locomotive or marine engines) or other nonroad diesel engine certified for the use of 15 ppm sulfur content fuel, or permit the introduction into the fuel system of such vehicle or nonroad engine of used motor oil, or used motor oil blended with diesel fuel, that does not comply with the requirements of § 80.522.

(e) *Improper fuel usage violation.* (1) Introduce, or permit the introduction of, fuel into model year 2007 or later diesel motor vehicles, and beginning December 1, 2010 into any diesel motor vehicle, that does not comply with the standards and dye requirements of § 80.520(a) and (b);

(2) Introduce, or permit the introduction of, fuel into any nonroad diesel engine (including any locomotive or marine diesel engine) that does not comply with the applicable standards, dye and marking requirements of § 80.510(a), (d), and (e) and § 80.520(b) beginning on the following dates:

(i) This prohibition begins December 1, 2007 in the areas specified in § 80.510(g)(1) and (g)(2), except as specified in paragraph (e)(2)(ii) of this section.

(ii) This prohibition begins December 1, 2010 in the area specified in § 80.510(g)(2) for NRLM diesel fuel that is produced in accordance with a compliance plan approved under § 80.554.

(iii) This prohibition begins December 1, 2010 in all other areas.

(3) Introduce, or permit the introduction of, fuel into any nonroad diesel engine (other than locomotive and marine diesel engines) that does not comply with the applicable standards, dye and marking requirements of § 80.510(b) and (e) beginning on the following dates:

(i) This prohibition begins December 1, 2010 in the areas specified in § 80.510(g)(1) and (g)(2), except as specified paragraph (e)(3)(ii) of this section.

(ii) This prohibition begins December 1, 2014 in the area specified in § 80.510(g)(2) for NRLM diesel fuel that is produced in accordance with a compliance plan approved under § 80.554.

(iii) This prohibition begins beginning December 1, 2014 in all other areas.

(4) Introduce, or permit the introduction of, fuel into any locomotive and marine diesel engine which does not comply with the applicable standards, dye and marking requirements of § 80.510(c) and § 80.510(f) in the following areas beginning on the following dates:

(i) This prohibition begins December 1, 2012 in the areas specified in § 80.510(g)(1) and (g)(2), except as specified in paragraph (e)(4)(ii) of this section.

(ii) This prohibition does not apply in the area specified in § 80.510(g)(2) for NRLM diesel fuel that is produced in accordance with a compliance plan approved under § 80.554.

(iii) This prohibition does not apply in any other areas.

(5) Introduce, or permit the introduction of, fuel into any model year 2011 or later nonroad diesel engine certified for use on 15 ppm sulfur

content fuel, diesel fuel which does not comply with the applicable standards, dye and marking requirements of § 80.510(b) through (f).

(f) *Cause another party to violate.* Cause another person to commit an act in violation of paragraphs (a) through (e) of this section.

(g) *Cause violating fuel or additive to be in the distribution system.* Cause motor vehicle diesel fuel, or NRLM diesel fuel, to be in the diesel fuel distribution system which does not comply with the applicable standard, dye or marker requirements or the product segregation requirements of this Subpart I, or cause any diesel fuel additive to be in the diesel fuel additive distribution system which does not comply with the applicable sulfur standards under § 80.521.

■ 68. Section 80.611 is revised to read as follows:

§ 80.611 What evidence may be used to determine compliance with the prohibitions and requirements of this subpart and liability for violations of this subpart?

(a) *Compliance with sulfur, cetane, and aromatics standards, dye and marker requirements.* Compliance with the standards, dye, and marker requirements in §§ 80.510, 80.511, 80.520, and 80.521 shall be determined based on the level of the applicable component or parameter, using the sampling methodologies specified in § 80.330(b), as applicable, and an approved testing methodology under the provisions of §§ 80.580 through 80.586 for sulfur; § 80.2(w) for cetane index; § 80.2(z) for aromatic content; and § 80.582 for fuel marker. Any evidence or information, including the exclusive use of such evidence or information, may be used to establish the level of the applicable component or parameter in the diesel fuel or additive, or motor oil to be used in diesel fuel, if the evidence or information is relevant to whether that level would have been in compliance with the standard if the regulatory sampling and testing methodology had been correctly performed. Such evidence may be obtained from any source or location and may include, but is not limited to, test results using methods other than the compliance methods in this paragraph (a), business records, and commercial documents.

(b) *Compliance with other requirements.* Determination of compliance with the requirements and prohibitions of this subpart other than the standards described in paragraph (a) of this section and in §§ 80.510, 80.511, 80.520, and 80.521, and determination of liability for any violation of this subpart, may be based on information obtained from any source or location. Such information may include, but is not limited to, business records and commercial documents.

■ 69. Section 80.612 is amended by revising paragraph (a) to read as follows:

§ 80.612 Who is liable for violations of this subpart?

(a) *Persons liable for violations of prohibited acts.* (1) *Standard, dye, marker, additives, used motor oil, heating oil, fuel introduction, and other product requirement violations.* (i) Any refiner, importer, distributor, reseller, carrier, retailer, wholesale purchaser-consumer who owned, leased, operated, controlled or supervised a facility where a violation of any provision of § 80.610(a) through (e) occurred, or any other person who violates any provision of § 80.610(a) through (e), is deemed liable for the applicable violation, except that distributors who receive diesel fuel or distillate from the point where it is taxed, dyed or marked, and retailers and wholesale purchaser-consumers are not deemed liable for any violation of § 80.610(b).

(ii) Any person who causes another person to violate § 80.610(a) through (e) is liable for a violation of § 80.610(f).

(iii) Any refiner, importer, distributor, reseller, carrier, retailer, or wholesale purchaser-consumer who produced, imported, sold, offered for sale, dispensed, supplied, offered to supply, stored, transported, or caused the transportation or storage of, diesel fuel or distillate that violates § 80.610(a), is deemed in violation of § 80.610(f).

(iv) Any person who produced, imported, sold, offered for sale, dispensed, supplied, offered to supply, stored, transported, or caused the transportation or storage of a diesel fuel additive which is used in motor vehicle diesel fuel or NRLM diesel fuel that is found to violate § 80.610(a), is deemed in violation of § 80.610(f).

(2) *Cause violating diesel fuel or additive to be in the distribution system.* Any refiner, importer, distributor, reseller, carrier, retailer, or wholesale purchaser-consumer or any other person who owned, leased, operated, controlled or supervised a facility from which distillate fuel or additive was released into the distribution system which does not comply with the applicable standards, marking or dye requirements of this Subpart I is deemed in violation of § 80.610(g).

(3) *Branded refiner/importer liability.* Any refiner or importer whose corporate, trade, or brand name, or whose marketing subsidiary's corporate, trade, or brand name appeared at a facility where a violation of § 80.610(a) or (b) occurred, is deemed in violation of § 80.610(a) or (b), as applicable.

(4) *Carrier causation.* In order for a distillate fuel or diesel fuel additive carrier to be liable under paragraph (a)(1)(ii), (a)(1)(iii), or (a)(1)(iv) of this section, as applicable, EPA must demonstrate, by reasonably specific showing by direct or circumstantial evidence, that the carrier caused the violation.

(5) *Parent corporation.* Any parent corporation is liable for any violations of this subpart that are committed by any subsidiary.

(6) *Joint venture.* Each partner to a joint venture is jointly and severally liable for any violation of this subpart that occurs at the joint venture facility or is committed by the joint venture operation.

* * * * *

■ 70. Section 80.613 is amended by revising the section heading and paragraphs (a) and (d) to read as follows:

§ 80.613 What defenses apply to persons deemed liable for a violation of a prohibited act under this subpart?

(a) *Presumptive liability defenses.* (1) Any person deemed liable for a violation of a prohibition under § 80.612(a)(1)(i), (a)(1)(iii), (a)(2), or (a)(3), will not be deemed in violation if the person demonstrates the following:

(i) The violation was not caused by the person or the person's employee or agent;

(ii) Product transfer documents account for fuel or additive found to be in violation and indicate that the violating product was in compliance with the applicable requirements when it was under the person's control;

(iii) The person conducted a quality assurance sampling and testing program, as described in paragraph (d) of this section, except for those persons subject to the provisions of paragraph (a)(1)(iv), (a)(1)(v), or (a)(1)(vi) of this section or § 80.614. A carrier may rely on the quality assurance program carried out by another party, including the party who owns the diesel fuel in question, provided that the quality assurance program is carried out properly. Retailers, wholesale purchaser-consumers, and ultimate consumers of diesel fuel are not required to conduct quality assurance programs;

(iv) For refiners and importers of diesel fuel subject to the 15 ppm sulfur standard under § 80.510(b) or (c), or § 80.520(a)(1), or the 500 ppm sulfur standard under § 80.510(a) or 80.520(c), test results that—

(A) Were conducted according to an appropriate test methodology approved or designated under §§ 80.580 through 80.586, 80.2(w), or 80.2(z), as appropriate; and

(B) Establish that, when it left the party's control, the fuel did not violate the sulfur, cetane or aromatics standard, or the dye or marking provisions of §§ 80.510 or 80.511, as applicable;

(v) For any truck loading terminal or any other person who delivers heating oil for delivery to the ultimate consumer and is subject to the requirement to mark heating oil or LM diesel fuel under § 80.510(d) through (f), data which demonstrates that when it left the truck loading terminal or other facility, the concentration of marker solvent yellow 124 was equal to or greater than six milligrams per liter. In lieu of testing for marker solvent yellow 124 concentration, evidence may be presented of an oversight program, including records of marker inventory, purchase and additization, and records of periodic inspection and calibration of additization equipment that ensures that marker is added to heating oil or LM diesel fuel, as applicable, under § 80.510(d) through (f) in the required concentration;

(vi) Except as provided in § 80.614, for any person who, at a downstream location, blends a diesel fuel additive subject to the requirements of § 80.521(b) into motor vehicle diesel fuel or NRLM diesel fuel subject to the 15 ppm sulfur standard under § 80.520(a) or § 80.510(b) or (c), except a person who blends additives into fuel tanker trucks at a truck loading rack subject to the provisions of paragraph (d)(2) of this section, test results which are conducted subsequent to the blending of the additive into the fuel, and which comply with the requirements of paragraphs (a)(1)(iv)(A) and (B) of this section; and

(vii) Any person deemed liable for a designation or volume balance provisions violation under § 80.610(b) and 80.612(a) will not be deemed in violation if the person demonstrates, through product transfer documents, records, reports and other evidence that the diesel fuel or distillate was properly designated and volume balance requirements were met.

(2) Any person deemed liable for a violation under § 80.612(a)(1)(iv), in regard to a diesel fuel additive subject to the requirements of § 80.521(a), will not be deemed in violation if the person demonstrates that—

(i) Product transfer document(s) account for the additive in the fuel found to be in violation, which comply with the requirements under § 80.591(a), and indicate that the additive was in compliance with the applicable requirements while it was under the party's control; and

(ii) For the additive's manufacturer or importer, test results which accurately establish that, when it left the party's control, the additive in the diesel fuel determined to be in violation did not have a sulfur content greater than or equal to 15 ppm.

(A) Analysis of the additive sulfur content pursuant to this paragraph (a)(2) may be conducted at the time the batch was manufactured or imported, or on a sample of that batch which the manufacturer or importer retains for such purpose for a minimum of two years from the date the batch was manufactured or imported.

(B) After two years from the date the additive batch was manufactured or imported, the additive manufacturer or importer is no longer required to retain samples for the purpose of complying with the testing requirements of this paragraph (a)(2).

(C) The analysis of the sulfur content of the additive must be conducted pursuant to the requirements of § 80.580.

(3) Any person who is deemed liable for a violation under § 80.612(a)(1)(iv) with regard to a diesel fuel additive subject to the requirements of § 80.521(b), will not be deemed in violation if the person demonstrates that—

(i) The violation was not caused by the party or the party's employee or agent;

(ii) Product transfer document(s) which comply with the additive information requirements under § 80.591(b), account for the additive in the fuel found to be in violation, and indicate that the additive was in compliance with the applicable requirements while it was under the party's control; and

(iii) For the additive's manufacturer or importer, test results which accurately establish that, when it left the party's control, the additive in the diesel fuel determined to be in violation was in conformity with the information on the additive product transfer document pursuant to the requirements of § 80.591(b). The testing procedures applicable under paragraph (a)(2) of this section, also apply under this paragraph (a)(3).

* * * * *

(d) *Quality assurance and testing program.* To demonstrate an acceptable quality assurance program under paragraph (a)(1)(iii) of this section, a person must present evidence of the following:

(1) A periodic sampling and testing program to ensure the diesel fuel or additive the person sold, dispensed, supplied, stored, or transported, meets the applicable standards and requirements, including the requirements relating to the presence of marker solvent yellow 124.

(2) For those parties who, at a downstream location, blend diesel fuel additives subject to the requirements of § 80.521(b) into fuel trucks at a truck loading rack, the periodic sampling and testing program required under this paragraph (d) must ensure, by taking into account the greater risk of noncompliance created through use of a high sulfur additive, that the diesel fuel into which the additive was blended meets the applicable standards subsequent to the blending.

(3) On each occasion when diesel fuel or additive is found not in compliance with the applicable standard:

(i) The person immediately ceases selling, offering for sale, dispensing, supplying, offering for supply, storing or transporting the non-complying product.

(ii) The person promptly remedies the violation and the factors that caused the violation (for example, by removing the non-complying product from the distribution system until the applicable standard is achieved and taking steps to prevent future violations of a similar nature from occurring).

(4) For any carrier who transports diesel fuel or additive in a tank truck, the quality assurance program required under this paragraph (d) need not include its own periodic sampling and testing of the diesel fuel or additive in the tank truck, but in lieu of such tank truck sampling and testing, the carrier shall demonstrate evidence of an oversight program for monitoring compliance with the requirements of this subpart relating to the transport or storage of such product by tank truck, such as appropriate guidance to drivers regarding compliance with the applicable sulfur standard, product segregation and product transfer document requirements, and the periodic review of records received in the ordinary course of business concerning diesel fuel or additive quality and delivery.

■ 71. Section 80.614 is revised to read as follows:

§ 80.614 What are the alternative defense requirements in lieu of § 80.613(a)(1)(vi) for static dissipater additives exceeding the 15 ppm sulfur standard but that contribute less than 0.05 ppm sulfur when added to MVNRLM diesel fuel?

Any person who blends a MVNRLM diesel fuel additive package into

MVNRLM diesel fuel subject to the 15 ppm sulfur standards of § 80.510(b) or (c) or § 80.520(a) which contains a static dissipater additive that has a sulfur content greater than 15 ppm but whose contribution to the sulfur content of the MVNRLM diesel fuel is less than 0.05 ppm at its maximum recommended concentration, and which contains no other additives with a sulfur content greater than 15 ppm must establish all the following in order to use this section as an alternative to the defense element under § 80.613(a)(1)(vi):

(a)(1) The blender of the static dissipater additive package has a sulfur content test result for the MVNRLM diesel fuel prior to blending of the additive that indicates that the additive package, when added, will not cause the MVNRLM diesel fuel sulfur content to exceed 15 ppm sulfur.

(2) In cases where the storage tank that contains MVNRLM diesel fuel prior to additization contains multiple fuel batches, the blender of the static dissipater additive package must have sulfur test results on each batch of MVNRLM diesel fuel that was added to the storage tank during the current and previous VAR periods, which indicates that the additive package, when added to the component MVNRLM diesel fuel batch in the storage tank with the highest sulfur level would not cause that component batch to exceed 15 ppm sulfur.

(b) The volumetric additive reconciliation (VAR) standard is attained as determined under the provisions of this section. The VAR reconciliation standard is attained when the actual concentration of a static dissipater additive package used per the VAR formula record under paragraph (f) of this section is less than the concentration that would have caused any batch of MVNRLM diesel fuel to exceed a sulfur content of 15 ppm given the maximum sulfur test result on any MVNRLM diesel fuel batch described in paragraph (a) of this section that is additized with the static dissipater additive package during the VAR period.

(c) The product transfer document complies with the applicable sulfur information requirements of § 80.591.

(d) If more than one static dissipater additive package is used during a VAR period, then a separate VAR formula record must be created for MVNRLM diesel fuel additized for each of the static dissipater additive packages used. In such cases, the amount of the each static dissipater additive package used must be accurately and separately measured, either through the use of a separate storage tank, a separate meter, or some other measurement system that is able to accurately distinguish its use.

(e) Recorded volumes of MVNRLM diesel fuel and static dissipater additive package must be expressed to the nearest gallon (or smaller units), except that static dissipater additive package volumes of five gallons or less must be expressed to the nearest tenth of a gallon (or smaller units). However, if the blender's equipment cannot accurately measure to the nearest tenth of a gallon, then such volumes must be rounded upward to the next higher gallon for purposes of determining compliance with this section.

(f) Each VAR formula record must also contain the following information:

(1) *Automated blending facilities.* In the case of an automated static dissipater additive package blending facility, for each VAR period, for each static dissipater additive package storage system, and each static dissipater additive package in that storage system, the following must be recorded:

(i)(A) The manufacturer and commercial identifying name of the static dissipater additive package being reconciled, the maximum recommended treatment level, the potential contribution to the sulfur content of the finished fuel that might result when the additive package is used at its maximum recommended treatment level, the intended treatment level, and the contribution to the sulfur content of the finished fuel that would result when the additive package is used at its intended treatment level. The intended treatment level is the treatment level that the additive injection equipment is set to.

(B) The maximum recommended treatment level and the intended treatment level must be expressed in terms of gallons of static dissipater additive package per thousand gallons of MVNRLM diesel fuel, and expressed to four significant figures. If the static dissipater additive package storage system which is the subject of the VAR formula record is a proprietary system under the control of a customer, this fact must be indicated on the record.

(ii) The total volume of static dissipater additive package blended into MVNRLM diesel fuel, in accordance with one of the following methods, as applicable.

(A) For a facility which uses in-line meters to measure static dissipater additive package usage, the total volume of static dissipater additive package measured, together with supporting data which includes one of the following: the beginning and ending meter readings for each meter being measured, the metered batch volume measurements for each meter being measured, or other comparable metered measurements. The supporting data may be supplied on the VAR formula record or in the form of computer printouts or other comparable VAR supporting documentation.

(B) For a facility which uses a gauge to measure the inventory of the static dissipater additive package storage tank, the total volume of static dissipater additive package shall be calculated from the following equation:

Static dissipater additive package Volume = (A) − (B) + (C) − (D)

Where:

A = Initial static dissipater additive package inventory of the tank

B = Final static dissipater additive package inventory of the tank

C = Sum of any additions to static dissipater additive package inventory

D = Sum of any withdrawals from static dissipater additive package inventory for purposes other than the additization of MVNRLM diesel fuel.

(C) The value of each variable in the equation in paragraph (f)(1)(ii)(B) of this section must be separately recorded on the VAR formula record. In addition, a list of each static dissipater additive package addition included in variable C and a list of each static dissipater additive package withdrawal included in variable D must be provided, either on the formula record or as VAR supporting documentation.

(iii) The total volume of MVNRLM diesel fuel to which static dissipater additive package has been added, together with supporting data which includes one of the following: the beginning and ending meter measurements for each meter being measured, the metered batch volume measurements for each meter being measured, or other comparable metered measurements. The supporting data may be supplied on the VAR formula record or in the form of computer printouts or other comparable VAR supporting documentation.

(iv) The actual static dissipater additive package concentration, calculated as the total volume of static dissipater additive package added (pursuant to paragraph (f)(1)(ii) of this section), divided by the total volume of MVNRLM diesel fuel (pursuant to paragraph (f)(1)(iii) of this section). The concentration must be calculated and recorded to 4 significant figures.

(v) A list of each static dissipater additive package concentration rate set for the static dissipater additive package that is the subject of the VAR record, together with the date and description of each adjustment to any initially set concentration. The concentration adjustment information may be supplied on the VAR formula record or in the form of computer printouts or other comparable VAR supporting documentation. No concentration setting is permitted above the maximum recommended concentration supplied by the additive manufacturer, except as described in paragraph (f)(1)(vii) of this section.

(vi) The dates of the VAR period, which shall be no longer than thirty-one days. If the VAR period is contemporaneous with a calendar month, then specifying the month will fulfill this requirement; if not, then the beginning and ending dates and times of the VAR period must be listed. The times may be supplied on the VAR formula record or in supporting documentation. Any adjustment to any static dissipater additive package concentration rate initially set in the VAR period shall terminate that VAR period and initiate a new VAR period, except as provided in paragraph (f)(1)(vii) of this section.

(vii) The concentration setting for a static dissipater additive package injector may be changed from the concentration initially set in the VAR period without terminating that VAR period, provided that:

(A) The purpose of the change is to correct a batch under-additization prior to the end of the VAR period and prior to the transfer of the batch to another party, or to correct an equipment malfunction where there has been no over-additization of the additive;

(B) The concentration is immediately returned after the correction to a concentration that fulfills the requirements of this paragraph (f);

(C) The blender creates and maintains documentation establishing the date and adjustments of the correction; and

(D) If the correction is initiated only to rectify an equipment malfunction, and the amount of static dissipater additive package used in this procedure is not added to MVNRLM diesel fuel within the compliance period, then this amount is subtracted from the static dissipater additive package volume listed on the VAR formula record. In such a case, the addition of this amount of static dissipater additive must be reflected in the following VAR period.

(viii) The measured sulfur level for each batch of MVNRLM diesel fuel to which a static dissipater additive package is added during each VAR period. In cases where the storage tank that contains MVNRLM diesel fuel prior to additization contains multiple fuel batches, a measured sulfur level on each batch added to the storage tank during the current and previous VAR periods must be recorded.

(2) *Non-automated facilities.* In the case of a facility in which hand blending or any other non-automated method is used to blend static dissipater additive packages, for each static dissipater additive package and for each batch of MVNRLM diesel fuel to which the static dissipater additive package is being added, the following shall be recorded:

(i) The manufacturer and commercial identifying name of the static dissipater additive package being reconciled, the maximum recommended treatment level, the potential contribution to the sulfur content of the finished fuel that might result when the fuel is used at its maximum recommended treatment level, the intended treatment level, and the contribution to the sulfur content of the finished fuel that would result when the additive package is used at its intended treatment level.

(A) The maximum recommended treatment level and the intended treatment level must be expressed in terms of gallons of static dissipater additive package per thousand gallons of MVNRLM diesel fuel, and expressed to four significant figures.

(B) If the static dissipater additive package storage system which is the subject of the VAR formula record is a proprietary system under the control of a customer, this fact must be indicated on the record.

(ii) The date of the additization that is the subject of the VAR formula record.

(iii) The volume of added static dissipater additive package.

(iv) The volume of the MVNRLM diesel fuel to which the static dissipater additive package has been added.

(v) The brand (if known) of MVNRLM diesel fuel.

(vi) The actual static dissipater additive package concentration, calculated as the volume of added static dissipater additive package (pursuant to paragraph (f)(1)(ii)(B) of this section), divided by the volume of MVNRLM diesel fuel (pursuant to paragraph (f)(1)(iii) of this section). The concentration must be calculated and recorded to four significant figures.

(vii) The measured sulfur level for each batch of MVNRLM diesel fuel to which a static dissipater additive package is added during each VAR period. In cases where the storage tanks that contains MVNRLM diesel fuel prior to additization contains multiple fuel batches, a measured sulfur level on each batch added to the storage tank during the current and previous VAR periods must be recorded.

(3) *VAR formula records.* Every VAR formula record created pursuant to paragraphs (f)(1) and (f)(2) of this section shall contain the following:

(i) The signature of the creator of the VAR record;

(ii) The date of the creation of the VAR record; and

(iii) A certification of correctness by the creator of the VAR record.

(4) *Electronically-generated VAR formula and supporting records.* (i) Electronically-generated records are acceptable for VAR formula records and supporting documentation (including PTDs), provided that they are complete, accessible, and easily readable. VAR formula records must also be stored with access and audit security, which must restrict to a limited number of specified people those who have the ability to alter or delete the records. In addition, parties maintaining records electronically must make available to EPA the hardware and software necessary to review the records.

(ii) Electronically-generated VAR formula records may use an electronic user identification code to satisfy the signature requirements of paragraph (f)(3)(i) of this section, provided that:

(A) The use of the identification is limited to the record creator; and

(B) A paper record is maintained, which is signed and dated by the VAR formula record creator, acknowledging that the use of that particular user ID on a VAR formula record is equivalent to his/her signature on the document.

(5) *Calibration requirements for automated blending facilities.* Automated static dissipater additive package blenders must calibrate their static dissipater additive package equipment at least once in each calendar half year, with the acceptable calibrations being no less than one hundred twenty days apart, except that calibrations may be closer in time so long as at least two calibrations meet the requirements to be in separate halves of the calendar year and no less than 120 days apart. Equipment recalibration is also required each time the static dissipater additive package is changed, unless written documentation indicates that the new static dissipater additive package has the same viscosity as the previous static dissipater additive package. Static dissipater package change calibrations may be used to satisfy the semiannual requirement provided that the calibrations occur in the appropriate half calendar year and are no less than one hundred twenty days apart.

(6) *Additional VAR documentation.* The following VAR supporting documentation must also be created and maintained:

(i) For all automated static dissipater additive package blending facilities, documentation reflecting performance of the calibrations required by paragraph (f)(5) of this section, and any associated adjustments of the automated static dissipater additive package injection equipment;

(ii) For all static dissipater additive package blending facilities, product transfer documents for all static dissipater additive packages, and static dissipater-additized MVNRLM diesel fuel transferred into or out of the facility;

(iii) For all automated static dissipater additive package blending facilities, documentation establishing the brands (if known) of the MVNRLM diesel fuel which is the subject of the VAR formula record; and

(iv) For all hand blending static dissipater additive package blenders, the documentation, if in the party's possession, supporting the volumes of MVNRLM diesel fuel and static dissipater additive package reported on the VAR formula record.

(7) *Document retention and availability.* All static dissipater additive package blenders shall retain the documents required under this section for a period of five years from the date the VAR formula records and supporting documentation are created, and shall deliver them upon request to the EPA Administrator or the Administrator's authorized representative.

(i) Except as provided in paragraph (f)(7)(iii) of this section, automated static dissipater additive package blender facilities and hand-blender facilities which are terminals, which physically blend static dissipater additive packages into MVNRLM diesel fuel, must make immediately available to EPA, upon request, the preceding twelve months of VAR formula records plus the preceding two months of VAR supporting documentation.

(ii) Except as provided in paragraph (f)(7)(iii) of this section, other hand-blending static dissipater additive package facilities which physically blend static dissipater additive package into MVNRLM diesel fuel must make immediately available to EPA, upon request, the preceding two months of VAR formula records and VAR supporting documentation.

(iii) Facilities which have centrally maintained records at other locations, or have customers who maintain their own records at other locations for their proprietary static dissipater additive package injection systems, and which can document this fact to the Agency, may have until the start of the next business day after the EPA request to supply VAR supporting documentation, or longer if approved by the Agency.

(iv) In this paragraph (f)(7), the term "immediately available" means that the records must be provided, electronically or otherwise, within approximately one hour of EPA's request, or within a longer time frame as approved by EPA.

■ 72. A new § 80.615 is added to read as follows:

§ 80.615 What penalties apply under this subpart?

(a) Any person liable for a violation under § 80.612 is subject to civil penalties as specified in section 205 of the Clean Air Act (42 U.S.C. 7524) for every day of each such violation and the amount of economic benefit or savings resulting from each violation.

(b)(1) Any person liable under § 80.612(a)(1) for a violation of an applicable standard or requirement under this Subpart I or for causing another party to violate such standard or requirement, is subject to a separate day of violation for each and every day the non-complying diesel fuel remains any place in the distribution system.

(2) Any person liable under § 80.612(a)(2) for causing motor vehicle diesel fuel, NRLM diesel fuel, heating oil, or other distillate fuel to be in the distribution system which does not comply with an applicable standard or requirement of this Subpart I is subject to a separate day of violation for each and every day that the non-complying diesel fuel remains any place in the diesel fuel distribution system.

(3) Any person liable under § 80.612(a)(1) for blending into diesel fuel an additive violating the applicable sulfur standard pursuant to the requirements of § 80.521(a) or (b), as applicable, or of causing another party to so blend such an additive, is subject to a separate day of violation for each and every day the motor vehicle diesel fuel or NRLM diesel fuel into which the noncomplying additive was blended, remains any place in the fuel distribution system.

(4) For purposes of this paragraph (b) of this section, the length of time the motor vehicle diesel fuel, NRLM diesel fuel, heating oil or other distillate fuel in question remained in the diesel fuel distribution system is deemed to be 25 days, unless a person subject to liability or EPA demonstrates by reasonably specific showings, by direct or circumstantial evidence, that the non-complying motor vehicle, NR or NRLM diesel fuel, heating oil or distillate fuel remained in the distribution system for fewer than or more than 25 days.

(c) Any person liable under § 80.612(b) for failure to meet, or causing a failure to meet, a provision of this subpart is liable for a separate day of violation for each and every day such provision remains unfulfilled.

■ 73. Section 80.620 is amended by revising the section heading and paragraphs (a), (b), (c), (d)(2), (d)(3)(i)(D), (e)(1), (f)(2)(ii) introductory text, (f)(3)(ii), (g), (h) introductory text, (h)(2), (i)(1)(v), (i)(1)(vi), (i)(5), (j), (k)(1), (k)(3), (n), (o), (p), (q), (r), and (s) to read as follows:

§ 80.620 What are the additional requirements for diesel fuel or distillates produced by foreign refineries subject to a temporary refiner compliance option, hardship provisions, or motor vehicle or NRLM diesel fuel credit provisions?

(a) *Definitions.* (1) A foreign refinery is a refinery that is located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as "the United States").

(2) A foreign refiner is a person who meets the definition of refiner under § 80.2(i) for a foreign refinery.

(3) A diesel fuel program foreign refiner ("DFR") is a foreign refiner that has been approved by EPA for participation in any motor vehicle diesel fuel or NRLM diesel fuel provision of § 80.530 through 80.533, or §§ 80.535, 80.536, 80.540, 80.552, 80.553, 80.554, 80.560 or 80.561 (collectively referred to as "diesel foreign refiner program").

(4) "DFR-Diesel" means diesel fuel or distillate fuel as applicable under subpart I of this part produced at a DFR refinery that is imported into the United States.

(5) "Non-DFR-Diesel" means diesel fuel or distillate fuel that is produced at a foreign refinery that has not been approved as a DFR foreign refiner, diesel fuel produced at a DFR foreign refinery that is not imported into the United States, and diesel fuel produced at a DFR foreign refinery during a period when the foreign refiner has opted to not participate in the DFR-Diesel foreign refiner program under paragraph (c)(3) of this section.

(6) "Certified DFR-Diesel" means DFR-Diesel the foreign refiner intends to include in the foreign refinery's compliance calculations under any provisions of § 80.530 through 80.533, or §§ 80.535, 80.536, 80.540, 80.552, 80.553, 80.554, 80.560 or 80.561 and does include in these compliance calculations when reported to EPA.

(7) "Non-Certified DFR-Diesel" means DFR-Diesel fuel that a DFR foreign

refiner imports to the United States that is not Certified DFR-Diesel.

(b) *Baseline*. For any foreign refiner to obtain approval under the diesel foreign refiner program of this subpart for any refinery, it must apply for approval under the applicable provisions of this subpart. To obtain approval the refiner is required, as applicable, to demonstrate a volume baseline under subpart I of this part.

(1) The refiner shall follow the procedures, applicable to volume baselines and using diesel fuel, or if applicable, heating oil, instead of gasoline, in §§ 80.91 through 80.93 to establish the volume of motor vehicle diesel fuel that was produced at the refinery and imported into the United States during the applicable years for purposes of establishing a baseline under Subpart I for applicable fuels produced for use in the United States.

(2) In making determinations for foreign refinery baselines EPA will consider all information supplied by a foreign refiner, and in addition may rely on any and all appropriate assumptions necessary to make such determinations.

(3) Where a foreign refiner submits a petition that is incomplete or inadequate to establish an accurate baseline, and the refiner fails to correct this deficiency after a request for more information, EPA will not assign an individual refinery baseline.

(c) *General requirements for DFR foreign refiners*. A foreign refiner of a refinery that is approved under the diesel foreign refiner program of this subpart must designate each batch of diesel fuel produced at the foreign refinery that is exported to the United States as either Certified DFR-Diesel or as Non-Certified DFR-Diesel, except as provided in paragraph (c)(3) of this section. It must further designate all Certified DFR-Diesel as provided in § 80.598, and designate whether the diesel fuel is dyed or undyed, and for heating oil and/or locomotive or marine diesel fuel whether it is marked or unmarked under § 80.510(d) through (f). It must further designate any credits earned as either nonroad diesel credits or motor vehicle diesel credits.

(1) In the case of Certified DFR-Diesel, the foreign refiner must meet all requirements that apply to refiners under this subpart, except that:

(i) For purposes of complying with the compliance option requirements of § 80.530, motor vehicle diesel fuel produced by a foreign refinery must comply separately for each Credit Trading Area of import, as defined in § 80.531(a)(5).

(ii) For purposes of complying with the compliance option requirements of § 80.530, credits obtained from any other refinery or from any importer must have been generated in the same Credit Trading Area as the Credit Trading Area of import of the fuel for which credits are needed to achieve compliance.

(iii) For purposes of generating credits under § 80.531, credits shall be generated separately by Credit Trading Area of import and shall be designated by Credit Trading Area of importation and by port of importation.

(2) In the case of Non-Certified DFR-Diesel, the foreign refiner shall meet all the following requirements:

(i) The designation requirements in this section.

(ii) The reporting requirements in this section and in §§ 80.593, 80.594, 80.601, and 80.604.

(iii) The product transfer document requirements in this section and in §§ 80.590 and 80.591.

(iv) The prohibitions in this section and in § 80.610.

(3)(i) Any foreign refiner that has been approved to produce diesel fuel subject to the diesel foreign refiner program for a foreign refinery under this subpart may elect to classify no diesel fuel imported into the United States as DFR-Diesel provided the foreign refiner notifies EPA of the election no later than 60 calendar days prior to the beginning of the compliance period.

(ii) An election under paragraph (c)(3)(i) of this section shall be for a 12 month compliance period and apply to all diesel fuel that is produced by the foreign refinery that is imported into the United States, and shall remain in effect for each succeeding year unless and until the foreign refiner notifies EPA of the termination of the election. The change in election shall take effect at the beginning of the next annual compliance period.

* * * * *

(d) * * *

(2) On each occasion when any person transfers custody or title to any DFR-Diesel prior to its being imported into the United States, it must include the following information as part of the product transfer document information in this section:

(i) Designation of the diesel fuel or distillate as Certified DFR-Diesel or as Non-Certified DFR-Diesel, and if it is Certified DFR-Diesel, further designate the fuel pursuant to § 80.598, and whether the diesel fuel or distillate is dyed or undyed, and for heating oil whether it is marked or unmarked under § 80.510(d) through (f), and all other applicable product transfer document information required under § 80.590; and

(ii) The name and EPA refinery registration number (under § 80.597) of the refinery where the DFR-Diesel was produced.

(3) * * *

(i) * * *

(D) In the case of Certified DFR-Diesel:

(*1*) The sulfur content as determined under paragraph (f) of this section, and the applicable designations stated in paragraph (d)(2)(i) of this section; and

(*2*) A declaration that the DFR-Diesel is being included in the applicable compliance calculations required by EPA under this subpart.

* * * * *

(e) * * *

(1)(i) The foreign refiner excludes:

(A) The volume of diesel from the refinery's compliance report under § 80.593, § 80.601, or § 80.604; and

(B) In the case of Certified DFR-Diesel, the volume of the diesel fuel from the compliance report under § 80.593, § 80.601, or § 80.604.

(ii) The exclusions under paragraph (e)(1)(i) of this section shall be on the basis of the designations under § 80.598 and this section, and volumes determined under paragraph (f) of this section.

* * * * *

(f) * * *

(2) * * *

(ii) Determine the sulfur content value for each compartment, and if applicable, the marker content under § 80.510(d) through (f) using an approved methodology as specified in §§ 80.580 through 80.586 by one of the following:

* * * * *

(3) * * *

(ii) To the Administrator containing the information required under paragraphs (f)(1) and (f)(2) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the method used to determine the identity of the refinery at which the diesel fuel or distillate was produced, assurance that the diesel fuel or distillate remained segregated as specified in paragraph (n)(1) of this section, and a description of the diesel fuel's movement and storage between production at the source refinery and vessel loading.

* * * * *

(g) *Comparison of load port and port of entry testing*. (1)(i) Any foreign refiner and any United States importer of Certified DFR-Diesel shall compare the results from the load port testing under paragraph (f) of this section, with the port of entry testing as reported under paragraph (o) of this section, for the volume of diesel fuel and the sulfur content value; except as specified in paragraph (g)(1)(ii) of this section.

(ii) Where a vessel transporting Certified DFR-Diesel off loads this diesel fuel at more than one United States port of entry, and the conditions of paragraph (g)(2)(i) of this section are met at the first United States port of entry, the requirements of paragraph (g)(2) of this section do not apply at subsequent ports of entry if the United States importer obtains a certification from the vessel owner that meets the requirements of paragraph (s) of this section, that the vessel has not loaded any diesel fuel or blendstock between the first United States port of entry and the subsequent port of entry.

(2)(i) The requirements of this paragraph (g)(2) apply if—

(A) The temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent; or

(B) The sulfur content value determined at the port of entry is higher than the sulfur content value determined at the load port, and the amount of this difference is greater than the reproducibility amount specified for the port of entry test result by the American Society of Testing and Materials (ASTM) for a test method used for testing the port of entry sample under the provisions §§ 80.580 through 80.586.

(ii) The United States importer and the foreign refiner shall treat the diesel fuel as Non-Certified DFR-Diesel, and the foreign refiner shall exclude the diesel fuel volume from its diesel fuel volumes calculations and sulfur standard designations under § 80.598.

(h) *Attest requirements.* Refiners, for each annual compliance period, must arrange to have an attest engagement performed of the underlying documentation that forms the basis of any report required under this subpart. The attest engagement must comply with the procedures and requirements that apply to refiners under §§ 80.125 through 80.130, or other applicable attest engagement provisions, and must be submitted to the Administrator of EPA by August 31 of each year for the prior annual compliance period. The following additional procedures shall be carried out for any foreign refiner of DFR-Diesel.

* * * * *

(2) Obtain separate listings of all tenders of Certified DFR-Diesel and of Non-Certified DFR-Diesel, and obtain separate listings of Certified DFR-Diesel based on whether it is 15 ppm sulfur content diesel fuel, 500 ppm sulfur content diesel fuel or high sulfur fuel having a sulfur content greater than 500 ppm (and if so, whether the fuel is heating oil, small refiner diesel fuel, diesel fuel produced through the use of credits, or other applicable designation under § 80.598). Agree the total volume of tenders from the listings to the diesel fuel inventory reconciliation analysis in § 80.128(b), and to the volumes determined by the third party under paragraph (f)(1) of this section.

* * * * *

(i) * * *

(1) * * *

(v) Inspections and audits by EPA may include review and copying of any documents related to:

(A) Refinery baseline establishment, if applicable, including the volume, sulfur content and dye and marker status of diesel fuel, heating oil and other distillates; transfers of title or custody of any diesel fuel, heating oil or blendstocks whether DFR-Diesel or Non-DFR-Diesel, produced at the foreign refinery during the period January 1, 1998 through the date of the refinery baseline petition or through the date of the inspection or audit if a baseline petition has not been approved, and any work papers related to refinery baseline establishment;

(B) The volume and sulfur content of DFR-Diesel;

(C) The proper classification of diesel fuel as being DFR-Diesel or as not being DFR-Diesel, or as Certified DFR-Diesel or as Non-Certified DFR-Diesel, and all other relevant designations under this subpart, including § 80.598 and this section;

(D) Transfers of title or custody to DFR-Diesel;

(E) Sampling and testing of DFR-Diesel;

(F) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers; and

(G) Reports prepared for submission to EPA, and any work papers related to such reports.

(vi) Inspections and audits by EPA may include taking samples of diesel fuel, heating oil, other distillates, diesel fuel additives or blendstock, dyes and chemical markers and interviewing employees.

* * * * *

(5) Submitting a petition for participation in the diesel foreign refiner program or producing and exporting diesel fuel or heating oil under any such program, and all other actions to comply with the requirements of this subpart relating to participation in any diesel foreign refiner program, or to establish an individual refinery motor vehicle diesel fuel volume baseline or other baseline under subpart I of this part (if applicable) constitute actions or activities that satisfy the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

* * * * *

(j) *Sovereign immunity.* By submitting a petition for participation in any diesel foreign refiner program under this subpart (and baseline, if applicable) under this section, or by producing and exporting diesel fuel to the United States under any such program, the foreign refiner, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(k) * * *

(1) The foreign refiner shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G \times \$\,0.01$$

Where:

Bond = amount of the bond in U.S. dollars

G = the applicable volume baseline under Subpart I for diesel fuel or distillate produced at the foreign refinery and exported to the United States, in gallons.

* * * * *

(3) Bonds posted under this paragraph (k) shall—

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States

Department of Treasury Circular 570 "Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds;" and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest annual reporting period that the foreign refiner produces diesel fuel pursuant to the requirements of this subpart.

* * * * *

(n) *Prohibitions.* (1) No person may combine Certified DFR-Diesel with any Non-Certified DFR-Diesel or Non–DFR-Diesel, and no person may combine Certified DFR-Diesel with any Certified DFR-Diesel produced at a different refinery, until the importer has met all the requirements of paragraph (o) of this section, except as provided in paragraph (e) of this section. No person may violate the product segregation requirements of § 80.511.

(2) No foreign refiner or other person may cause another person to commit an action prohibited in paragraph (n)(1) of this section, or that otherwise violates the requirements of this section.

(o) *United States importer requirements.* Any United States importer shall meet the following requirements:

(1) Each batch of imported diesel fuel and heating oil shall be classified by the importer as being DFR-Diesel or as Non-DFR-Diesel, and each batch classified as DFR-Diesel shall be further classified as Certified DFR-Diesel or as Non-Certified DFR-Diesel, and each batch of Certified DFR-Diesel shall be further designated pursuant to the designation requirements of § 80.598 and this section.

(2) Diesel fuel shall be classified as Certified DFR-Diesel or as Non-Certified DFR-Diesel according to the designation by the foreign refiner if this designation is supported by product transfer documents prepared by the foreign refiner as required in paragraph (d) of this section, unless the diesel fuel is classified as Non-Certified DFR-Diesel under paragraph (g) of this section. Additionally, the importer shall comply with all requirements of this subpart applicable to importers.

(3) For each diesel fuel batch classified as DFR-Diesel, any United States importer shall perform the following procedures.

(i) In the case of both Certified and Non-Certified DFR-Diesel, have an independent third party:

(A) Determine the volume of diesel fuel in the vessel;

(B) Use the foreign refiner's DFR-Diesel certification to determine the name and EPA-assigned registration number of the foreign refinery that produced the DFR-Diesel;

(C) Determine the name and country of registration of the vessel used to transport the DFR-Diesel to the United States; and

(D) Determine the date and time the vessel arrives at the United States port of entry.

(ii) In the case of Certified DFR-Diesel, have an independent third party:

(A) Collect a representative sample from each vessel compartment subsequent to the vessel's arrival at the United States port of entry and prior to off loading any diesel fuel from the vessel;

(B) Obtain the compartment samples; and

(C) Determine the sulfur content value, and if applicable, the marker content, of each compartment sample using an appropriate methodology as specified in §§ 80.580 through 80.586 by the third party analyzing the sample or by the third party observing the importer analyze the sample.

(4) Any importer shall submit reports within 30 days following the date any vessel transporting DFR-Diesel arrives at the United States port of entry:

(i) To the Administrator containing the information determined under paragraph (o)(3) of this section; and

(ii) To the foreign refiner containing the information determined under paragraph (o)(3)(ii) of this section, and including identification of the port and Credit Trading Area at which the product was offloaded.

(5) Any United States importer shall meet the requirements specified in §§ 80.510 and 80.520 and all other requirements of this subpart, for any imported diesel fuel or heating oil that is not classified as Certified DFR-Diesel under paragraph (o)(2) of this section.

(p) *Truck imports of Certified DFR-Diesel produced at a foreign refinery.* (1) Any refiner whose Certified DFR-Diesel is transported into the United States by truck may petition EPA to use alternative procedures to meet the following requirements:

(i) Certification under paragraph (d)(5) of this section;

(ii) Load port and port of entry sampling and testing under paragraphs (f) and (g) of this section;

(iii) Attest under paragraph (h) of this section; and

(iv) Importer testing under paragraph (o)(3) of this section.

(2) These alternative procedures must ensure Certified DFR-Diesel remains segregated from Non-Certified DFR-Diesel and from Non-DFR-Diesel until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses the following:

(i) Provisions for monitoring pipeline shipments, if applicable, from the refinery, that ensure segregation of Certified DFR-Diesel from that refinery from all other diesel fuel;

(ii) Contracts with any terminals and/or pipelines that receive and/or transport Certified DFR-Diesel, that prohibit the commingling of Certified DFR-Diesel with any of the following:

(A) Other Certified DFR-Diesel from other refineries.

(B) All Non-Certified DFR-Diesel.

(C) All Non-DFR-Diesel.

(D) All diesel fuel or heating oil products required to be segregated under this subpart;

(iii) Procedures for obtaining and reviewing truck loading records and United States import documents for Certified DFR-Diesel to ensure that such diesel fuel is only loaded into trucks making deliveries to the United States;

(iv) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation, or other criteria, to confirm that all Certified DFR-Diesel remains segregated throughout the distribution system and is only loaded into trucks for import into the United States.

(3) The petition required by this section must be submitted to EPA along with the application for temporary refiner relief individual refinery diesel sulfur standard under this subpart.

(q) *Withdrawal or suspension of a foreign refinery's temporary refinery flexibility program approval.* EPA may withdraw or suspend a diesel refiner baseline or standard approval for a foreign refinery where—

(1) A foreign refiner fails to meet any requirement of this section;

(2) A foreign government fails to allow EPA inspections as provided in paragraph (i)(1) of this section;

(3) A foreign refiner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart; or

(4) A foreign refiner fails to pay a civil or criminal penalty that is not satisfied using the foreign refiner bond specified in paragraph (k) of this section.

(r) *Early use of a foreign refiner motor vehicle diesel fuel baseline.* (1) A foreign refiner may begin using an individual refinery baseline under subpart I of this part before EPA has approved the baseline, provided that:

(i) A baseline petition has been submitted as required in paragraph (b) of this section;

(ii) EPA has made a provisional finding that the baseline petition is complete;

(iii) The foreign refiner has made the commitments required in paragraph (i) of this section;

(iv) The persons who will meet the independent third party and independent attest requirements for the foreign refinery have made the commitments required in paragraphs (f)(3)(iii) and (h)(7)(iii) of this section; and

(v) The foreign refiner has met the bond requirements of paragraph (k) of this section.

(2) In any case where a foreign refiner uses an individual refinery baseline before final approval under paragraph (r)(1) of this section, and the foreign refinery baseline values that ultimately are approved by EPA are more stringent than the early baseline values used by the foreign refiner, the foreign refiner shall recalculate its compliance, *ab initio,* using the baseline values approved by the EPA, and the foreign refiner shall be liable for any resulting violation of the motor vehicle highway diesel fuel requirements.

(s) *Additional requirements for petitions, reports and certificates.* Any petition for approval to produce diesel fuel subject to the diesel foreign refiner program, any alternative procedures under paragraph (p) of this section, any report or other submission required by paragraph (c), (f)(2), or (i) of this section, and any certification under paragraph (d)(3) of this section shall be—

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Be signed by the president or owner of the foreign refiner company, or by that person's immediate designee, and shall contain the following declaration:

I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [insert name of foreign refiner] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart I, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof.

I affirm that I have read and understand the provisions of 40 CFR part 80, subpart I, including 40 CFR 80.620 apply to [insert name of foreign refiner]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.

PART 86—CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES

■ 74. The authority citation for part 86 continues to read as follows:

Authority: 42 U.S.C. 7401—7671(q).

■ 75. Section 86.007–35 is amended by revising paragraph (c) to read as follows:

§ 86.007–35 Labeling.

* * * * *

(c) Model year 2007 and later diesel-fueled vehicles must include permanent readily visible labels on the dashboard (or instrument panel) and near all fuel inlets that state "Use Ultra Low Sulfur Diesel Fuel Only" or "Ultra Low Sulfur Diesel Fuel Only".

* * * * *

■ 76. Section 86.007–38 is amended by revising paragraph (i) to read as follows:

§ 86.007–38 Maintenance instructions.

* * * * *

(i) For each new diesel-fueled engine subject to the standards prescribed in § 86.007–11, as applicable, the manufacturer shall furnish or cause to be furnished to the ultimate purchaser a statement that "This engine must be operated only with ultra low-sulfur diesel fuel (meeting EPA specifications for highway diesel fuel, including a 15 ppm sulfur cap)."

PART 89—CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES

■ 77. The authority citation for part 89 continues to read as follows:

Authority: 42 U.S.C. 7521, 7522, 7523, 7524, 7525, 7541, 7542, 7543, 7545, 7547, 7549, 7550, and 7601(a).

■ 78. Section 89.1 is amended by adding paragraph (b)(6) to read as follows:

§ 89.1 Applicability.

* * * * *

(b) * * *

(6) *Tier 4 engines.* This part does not apply to engines that are subject to emission standards under 40 CFR part 1039. See 40 CFR 1039.1 to determine when that part 1039 applies. Note that certain requirements and prohibitions apply to engines built on or after January 1, 2006 if they are installed in stationary applications or in equipment that will be used solely for competition, as described in 40 CFR 1039.1 and 40 CFR 1068.1; those provisions apply instead of the provisions of this part 89.

■ 79. Section 89.2 is amended by adding a definition for "Sulfur-sensitive technology" in alphabetical order to read as follows:

§ 89.2 Definitions.

* * * * *

Sulfur-sensitive technology means an emission-control technology that experiences a significant drop in emission-control performance or emission-system durability when an engine is operated on low-sulfur fuel (*i.e.*, fuel with a sulfur concentration up to 500 ppm) as compared to when it is operated on ultra low-sulfur fuel (*i.e.*, fuel with a sulfur concentration less than 15 ppm). Exhaust-gas recirculation is not a sulfur-sensitive technology.

* * * * *

■ 80. Section 89.112 is amended by revising the introductory text of paragraph (f)(1) and adding paragraph (g) to read as follows:

§ 89.112 Oxides of nitrogen, carbon monoxide, hydrocarbon, and particulate matter exhaust emission standards.

* * * * *

(f) * * *

(1) *Voluntary standards.* Engines may be designated "Blue Sky Series" engines by meeting the voluntary standards listed in Table 3, which apply to all certification and in-use testing, as follows:

* * * * *

(g) Manufacturers of engines at or above 37 kW and below 56 kW from model years 2008 through 2012 that are subject to the standards of this section under 40 CFR 1039.102 must take the following additional steps:

(1) State the applicable PM standard on the emission control information label.

(2) Add information to the emission-related installation instructions to clarify the equipment manufacturer's obligations under 40 CFR 1039.104(f).

■ 81. Section 89.114 is amended by adding a new paragraph (b)(3) to read as follows:

§ 89.114 Special and alternate test procedures.

* * * * *

(b) * * *

(3) A manufacturer may elect to use the test procedures in 40 CFR part 1065 as an alternate test procedure without advance approval by the Administrator. The manufacturer must identify in its application for certification that the engines were tested using the procedures in 40 CFR part 1065.

■ 82. Section 89.203 is amended by adding a new paragraph (c)(6) to read as follows:

§ 89.203 General provisions.

* * * * *

(c) * * *

(6) Model year 2008 and 2009 engines rated under 8 kW that are allowed to certify under this part because they meet the criteria in 40 CFR 1039.101(c) may not generate emission credits.

■ 83. Section 89.330 is amended by revising paragraph (b)(3) and adding paragraph (e) to read as follows:

§ 89.330 Lubricating oil and test fuels.

* * * * *

(b) * * *

(3) Testing of Tier 1 and Tier 2 engines rated under 37 kW and Tier 2 and Tier 3 engines rated at or above 37 kW that is conducted by the Administrator shall be performed using test fuels that meet the specifications in Table 4 in Appendix A of this subpart and that have a sulfur content no higher than 0.20 weight percent.

* * * * *

(e) *Low-sulfur test fuel.* (1) Upon request, for engines rated at or above 75 kW in model years 2006 or 2007, the diesel test fuel may be the low-sulfur diesel test fuel specified in 40 CFR part 1065, subject to the provisions of this paragraph (e)(1).

(i) To use this option, the manufacturer must—

(A) Ensure that ultimate purchasers of equipment using these engines are informed that the use of fuel meeting the 500 ppm specification is recommended.

(B) Recommend to equipment manufacturers that a label be applied at the fuel inlet recommending 500 ppm fuel.

(ii) None of the engines in the engine family may employ sulfur-sensitive technologies.

(iii) For engines rated at or above 130 kW, this option may be used in 2006 and 2007. For engines rated at or above 75 kW and under 130 kW, this option may be used only in 2007.

(2) For model years 2008 through 2010, except as otherwise provided, the diesel test fuel shall be the low-sulfur diesel test fuel specified in 40 CFR part 1065.

(3) The diesel test fuel shall be the ultra low-sulfur diesel test fuel specified in 40 CFR part 1065 for model years 2011 and later.

(4) For model years 2007 through 2010 engines that use sulfur-sensitive emission-control technology, the diesel test fuel is the ultra low-sulfur fuel specified in 40 CFR part 1065 if the manufacturer demonstrates that the in-use engines will use only fuel with 15 ppm or less of sulfur.

(5) Instead of the test fuels described in paragraphs (e)(2) through (4) of this section, for model years 2008 and later, manufacturers may use the test fuel described in appendix A of this subpart. In such cases, the test fuel described in appendix A of this subpart shall be the test fuel for all manufacturer and EPA testing.

■ 84. Section 89.908 is amended by adding paragraph (c) to read as follows:

§ 89.908 National security exemption.

* * * * *

(c) Manufacturers must add a legible label, written in block letters in English, to each engine exempted under this section. The label must be permanently secured to a readily visible part of the engine needed for normal operation and not normally requiring replacement, such as the engine block. This label must include at least the following items:

(1) The label heading "EMISSION CONTROL INFORMATION".

(2) Your corporate name and trademark.

(3) Engine displacement, engine family identification (as applicable), and model year of the engine or whom to contact for further information.

(4) The statement "THIS ENGINE HAS AN EXEMPTION FOR NATIONAL SECURITY UNDER 40 CFR 89.908.".

■ 85. Section 89.910 is amended by adding paragraph (c) to read as follows:

§ 89.910 Granting of exemptions.

* * * * *

(c) Manufacturers may ask EPA to apply the provisions of 40 CFR 1068.201(i) to engines exempted or excluded under this subpart.

PART 94—CONTROL OF AIR POLLUTION FROM MARINE COMPRESSION-IGNITION ENGINES

■ 86. The authority citation for part 94 continues to read as follows:

Authority: 42 U.S.C. 7522, 7523, 7524, 7525, 7541, 7542, 7543, 7545, 7547, 7549, 7550, and 7601(a).

■ 87. Section 94.908 is amended by adding paragraph (c) to read as follows:

§ 94.908 National security exemption.

* * * * *

(c) Manufacturers must add a legible label, written in block letters in English, to each engine exempted under this section. The label must be permanently secured to a readily visible part of the engine needed for normal operation and not normally requiring replacement, such as the engine block. This label must include at least the following items:

(1) The label heading "EMISSION CONTROL INFORMATION".

(2) Your corporate name and trademark.

(3) Engine displacement, engine family identification (as applicable), and model year of the engine or whom to contact for further information.

(4) The statement "THIS ENGINE HAS AN EXEMPTION FOR NATIONAL SECURITY UNDER 40 CFR 94.908.".

■ 88. A new part 1039 is added to subchapter U of chapter I, to read as follows:

SUBCHAPTER U—AIR POLLUTION CONTROLS

PART 1039—CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES

Subpart A—Overview and Applicability

Sec.

Subpart B—Emission Standards and Related Requirements

Subpart C—Certifying Engine Families

Authority: 42 U.S.C. 7401–7671(q).

Subpart A—Overview and Applicability

§ 1039.1 Does this part apply for my engines?

(a) The regulations in this part 1039 apply for all new, compression-ignition nonroad engines (defined in § 1039.801), except as provided in § 1039.5.

(b) This part 1039 applies as follows:

(1) This part 1039 applies for all engines subject to the emission standards specified in subpart B of this part starting with the model years noted in the following table:

TABLE 1 OF § 1039.1.—PART 1039 APPLICABILITY BY MODEL YEAR

Power category	Model year
kW < 19	[1] 2008
19 ≤ kW < 56	[2] 2008
56 ≤ kW < 130	2012
130 ≤ kW ≤ 560	2011
kW > 560	2011

[1] As described in § 1039.102, some engines below 19 kW may not be subject to the emission standards in this part until the 2010 model year.

[2] As described in § 1039.102, some engines in the 19–56 kW power category may not be subject to the emission standards in this part until the 2012 model year.

(2) If you use the provisions of § 1039.104(a) to certify an engine to the emission standards of this part before the model years shown in Table 1 of this section, all the requirements of this part apply for those engines.

(3) See 40 CFR part 89 for requirements that apply to engines not yet subject to the requirements of this part 1039.

(4) This part 1039 applies for other compression-ignition engines as follows:

(i) The provisions of paragraph (c) of this section and § 1039.801 apply for stationary engines beginning January 1, 2006.

(ii) The provisions of § 1039.620 and § 1039.801 apply for engines used solely for competition beginning January 1, 2006.

(c) The definition of nonroad engine in 40 CFR 1068.30 excludes certain engines used in stationary applications. These engines are not required to comply with this part, except for the requirements in § 1039.20. In addition, the prohibitions in 40 CFR 1068.101 restrict the use of stationary engines for nonstationary purposes.

(d) In certain cases, the regulations in this part 1039 apply to engines at or above 250 kW that would otherwise be covered by 40 CFR part 1048. See 40 CFR 1048.620 for provisions related to this allowance.

§ 1039.5 Which engines are excluded from this part's requirements?

This part does not apply to the following nonroad engines:

(a) *Locomotive engines.* (1) The following locomotive engines are not subject to the provisions of this part 1039:

(i) Engines in locomotives subject to the standards of 40 CFR part 92.

(ii) Engines in locomotives that are exempt from the standards of 40 CFR part 92 pursuant to the provisions of 40 CFR part 92 (except for the provisions of 40 CFR 92.907). For example, an engine that is exempt under 40 CFR

92.906 because it is in a manufacturer-owned locomotive is not subject to the provisions of this part 1039.

(2) The following locomotive engines are subject to the provisions of this part 1039:

(i) Engines in locomotives exempt from 40 CFR part 92 pursuant to the provisions of 40 CFR 92.907.

(ii) Locomotive engines excluded from the definition of locomotive in 40 CFR 92.2.

(b) *Marine engines.* (1) The following marine engines are not subject to the provisions of this part 1039:

(i) Engines subject to the standards of 40 CFR part 94.

(ii) Engines not subject to the standards of 40 CFR part 94 only because they were produced before the standards of 40 CFR part 94 started to apply.

(iii) Engines that are exempt from the standards of 40 CFR part 94 pursuant to the provisions of 40 CFR part 94 (except for the provisions of 40 CFR 94.907). For example, an engine that is exempt under 40 CFR 94.906 because it is a manufacturer-owned engine is not subject to the provisions of this part 1039.

(iv) Engines with rated power below 37 kW.

(v) Engines on foreign vessels.

(2) Marine engines are subject to the provisions of this part 1039 if they are exempt from 40 CFR part 94 based on the engine-dressing provisions of 40 CFR 94.907.

(c) *Mining engines.* Engines used in underground mining or in underground mining equipment and regulated by the Mining Safety and Health Administration in 30 CFR parts 7, 31, 32, 36, 56, 57, 70, and 75 are not subject to the provisions of this part 1039.

(d) *Hobby engines.* Engines with per-cylinder displacement below 50 cubic centimeters are not subject to the provisions of this part 1039.

§ 1039.10 How is this part organized?

The regulations in this part 1039 contain provisions that affect both engine manufacturers and others. However, the requirements of this part are generally addressed to the engine manufacturer. Unless we specifically state otherwise, the term "you" means the engine manufacturer, as defined in § 1039.801. This part 1039 is divided into the following subparts:

(a) Subpart A of this part defines the applicability of part 1039 and gives an overview of regulatory requirements.

(b) Subpart B of this part describes the emission standards and other requirements that must be met to certify engines under this part. Note that § 1039.102 and § 1039.104 discuss certain interim requirements and compliance provisions that apply only for a limited time.

(c) Subpart C of this part describes how to apply for a certificate of conformity.

(d) [Reserved]

(e) Subpart E of this part describes general provisions for testing in-use engines.

(f) Subpart F of this part describes how to test your engines (including references to other parts of the Code of Federal Regulations).

(g) Subpart G of this part and 40 CFR part 1068 describe requirements, prohibitions, and other provisions that apply to engine manufacturers, equipment manufacturers, owners, operators, rebuilders, and all others.

(h) Subpart H of this part describes how you may generate and use emission credits to certify your engines.

(i) Subpart I of this part contains definitions and other reference information.

§ 1039.15 Do any other regulation parts apply to me?

(a) Part 1065 of this chapter describes procedures and equipment specifications for testing engines. Subpart F of this part 1039 describes how to apply the provisions of part 1065 of this chapter to determine whether engines meet the emission standards in this part.

(b) The requirements and prohibitions of part 1068 of this chapter apply to everyone, including anyone who manufactures, imports, installs, owns, operates, or rebuilds any of the engines subject to this part 1039, or equipment containing these engines. Part 1068 of this chapter describes general provisions, including these seven areas:

(1) Prohibited acts and penalties for engine manufacturers, equipment manufacturers, and others.

(2) Rebuilding and other aftermarket changes.

(3) Exclusions and exemptions for certain engines.

(4) Importing engines.

(5) Selective enforcement audits of your production.

(6) Defect reporting and recall.

(7) Procedures for hearings.

(c) Other parts of this chapter apply if referenced in this part.

§ 1039.20 What requirements from this part apply to excluded stationary engines?

The provisions of this section apply for engines built on or after January 1, 2006.

(a) You must add a permanent label or tag to each new engine you produce or import that is excluded under § 1039.1(c) as a stationary engine. To meet labeling requirements, you must do the following things:

(1) Attach the label or tag in one piece so no one can remove it without destroying or defacing it.

(2) Secure it to a part of the engine needed for normal operation and not normally requiring replacement.

(3) Make sure it is durable and readable for the engine's entire life.

(4) Write it in English.

(5) Follow the requirements in § 1039.135(g) regarding duplicate labels if the engine label is obscured in the final installation.

(b) Engine labels or tags required under this section must have the following information:

(1) Include the heading "EMISSION CONTROL INFORMATION".

(2) Include your full corporate name and trademark. You may instead include the full corporate name and trademark of another company you choose to designate.

(3) State the engine displacement (in liters) and maximum engine power.

(4) State: "THIS ENGINE IS EXCLUDED FROM THE REQUIREMENTS OF 40 CFR PART 1039 AS A "STATIONARY ENGINE." INSTALLING OR USING THIS ENGINE IN ANY OTHER APPLICATION MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.".

Subpart B—Emission Standards and Related Requirements

§ 1039.101 What exhaust emission standards must my engines meet after the 2014 model year?

The exhaust emission standards of this section apply after the 2014 model year. Certain of these standards also apply for model year 2014 and earlier. This section presents the full set of emission standards that apply after all the transition and phase-in provisions of § 1039.102 and § 1039.104 expire. See § 1039.102 and 40 CFR 89.112 for exhaust emission standards that apply to 2014 and earlier model years. Section 1039.105 specifies smoke standards.

(a) *Emission standards for transient testing.* Transient exhaust emissions from your engines may not exceed the applicable emission standards in Table 1 of this section. Measure emissions using the applicable transient test procedures described in subpart F of this part. The following engines are not subject to the transient standards in this paragraph (a):

(1) Engines above 560 kW.

(2) Constant-speed engines.

(b) *Emission standards for steady-state testing.* Steady-state exhaust emissions from your engines may not exceed the applicable emission standards in Table 1 of this section. Measure emissions using the applicable steady-state test procedures described in subpart F of this part.

TABLE 1 OF § 1039.101.—TIER 4 EXHAUST EMISSION STANDARDS AFTER THE 2014 MODEL YEAR, G/KW-HR [1]

Maximum engine power	Application	PM	NO_X	NMHC	NO_X+NMHC	CO
kW < 19	All	[2] 0.40			7.5	[3] 6.6
19 ≤ kW < 56	All	0.03			4.7	[4] 5.0
56 ≤ kW < 130	All	0.02	0.40	0.19		5.0
130 ≤ kW ≤ 560	All	0.02	0.40	0.19		3.5
	Generator sets	0.03	0.67	0.19		3.5
kW > 560	All except generator sets	0.04	3.5	0.19		3.5

[1] Note that some of these standards also apply for 2014 and earlier model years. This table presents the full set of emission standards that apply after all the transition and phase-in provisions of § 1039.102 expire.
[2] See paragraph (c) of this section for provisions related to an optional PM standard for certain engines below 8 kW.
[3] The CO standard is 8.0 g/kW-hr for engines below 8 kW.
[4] The CO standard is 5.5 g/kW-hr for engines below 37 kW.

(c) *Optional PM standard for engines below 8 kW.* You may certify hand-startable, air-cooled, direct injection engines below 8 kW to an optional Tier 4 PM standard of 0.60 g/kW-hr. The term hand-startable generally refers to engines that are started using a hand crank or pull cord. This PM standard applies to both steady-state and transient testing, as described in paragraphs (a) and (b) of this section. Engines certified under this paragraph (c) may not be used to generate PM or NO_X+NMHC emission credits under the provisions of subpart H of this part. These engines may use PM or NO_X+NMHC emission credits, subject to the FEL caps in paragraph (d)(1) of this section.

(d) *Averaging, banking, and trading.* You may generate or use emission credits under the averaging, banking, and trading (ABT) program, as described in subpart H of this part. This requires that you specify a family emission limit (FEL) for each pollutant you include in the ABT program for each engine family. These FELs serve as the emission standards for the engine family with respect to all required testing instead of the standards specified in paragraphs (a) and (b) of this section. The FELs determine the not-to-exceed standards for your engine family, as specified in paragraph (e) of this section.

(1) *Primary FEL caps.* The FEL may not be higher than the limits in Table 2 of this section, except as allowed by paragraph (d)(2) of this section or by § 1039.102:

TABLE 2 OF § 1039.101.—TIER 4 FEL CAPS AFTER THE 2014 MODEL YEAR, G/KW-HR

Maximum engine power	Application	PM	NO_X	NO_X+NMHC
kW < 19	All	0.80		[1] 9.5
19 ≤ kW < 56	All	0.05		7.5
56 ≤ kW < 130	All	0.04	0.80	
130 ≤ kW ≤ 560	All	0.04	0.80	
kW > 560	Generator sets	0.05	1.07	
	All except generator sets	0.07	6.2	

[1] For engines below 8 kW, the FEL cap is 10.5 g/kW-hr for NO_X+NMHC emissions.

(2) *Alternate FEL caps.* For a given power category, you may use the alternate FEL caps shown in Table 3 of this section instead of the FEL caps identified in paragraph (d)(1) of this section for up to 5 percent of your U.S.-directed production volume in a given model year.

Maximum engine power	Starting model year [1]	PM FEL cap	NO_X FEL cap
19 ≤ kW < 56	[2] 2016	0.30	
56 ≤ kW < 130	2016	[3] 0.30	[3] 3.8
130 ≤ kW ≤ 560	2015	0.20	3.8
kW > 560	2019	0.10	[4] 3.5

[1] See § 1039.104(g) for alternate FEL caps that apply in earlier model years.
[2] For manufacturers certifying engines under Option #1 of Table 3 of § 1039.102, these alternate FEL caps apply starting with the 2017 model year.
[3] For engines below 75 kW, the FEL caps are 0.40 g/kW-hr for PM emissions and 4.4 g/kW-hr for NO_X emissions.
[4] For engines above 560 kW, the provision for alternate NO_X FEL caps is limited to generator-set engines. For example, if you produce 1,000 generator-set engines above 560 kW in a given model year, up to 50 of them may be certified to the alternate NO_X FEL caps.

(e) *Not-to-exceed standards.* Exhaust emissions from your engines may not exceed the applicable not-to-exceed (NTE) standards in this paragraph (e).

(1) Measure emissions using the procedures described in subpart F of this part.

(2) Except as noted in paragraph (e)(7) of this section, the NTE standard, rounded to the same number of decimal places as the applicable standard in Table 1 of this section, is determined from the following equation:

NTE standard for each pollutant = (STD) × (M)

Where:

STD = The standard specified for that pollutant in Table 1 of this section (or paragraph (c) of this section) if you certify without using ABT for that pollutant; or the FEL for that pollutant if you certify using ABT.

M = The NTE multiplier for that pollutant, as defined in paragraph (e)(3) of this section.

(3) The NTE multiplier for each pollutant is 1.25, except in the following cases:

If . . .	Or . . .	Then . . .
(i) The engine family is certified to a NO_X standard less than 2.50 g/kW-hr without using ABT.	The engine family is certified to a NO_X FEL less than 2.50 g/kW-hr or a NO_X+NMHC FEL less than 2.70 g/kW-hr.	The multiplier for NO_X, NMHC, and NO_X+NMHC is 1.50.
(ii) The engine family is certified to a PM standard less than 0.07 g/kW-hr without using ABT.	The engine family is certified to a PM FEL less than 0.07 g/kW-hr.	The multiplier for PM is 1.50.

(4) There are two sets of specifications of ambient operating regions that will apply for all NTE testing of engines in an engine family. You must choose one set for each engine family and must identify your choice of ambient operating regions in each application for certification for an engine family. You may choose separately for each engine family. Choose one of the following ambient operating regions:

(i) All altitudes less than or equal to 5,500 feet above sea level during all ambient temperature and humidity conditions.

(ii) All altitudes less than or equal to 5,500 feet above sea level, for temperatures less than or equal to the temperature determined by the following equation at the specified altitude:

$$T = -0.00254 \times A + 100$$

Where:

T = ambient air temperature in degrees Fahrenheit.

A = altitude in feet above sea level (A is negative for altitudes below sea level).

(5) Temperature and humidity ranges for which correction factors are allowed are specified in 40 CFR 86.1370–2007(e).

(i) If you choose the ambient operating region specified in paragraph (e)(4)(i) of this section, the temperature and humidity ranges for which correction factors are allowed are defined in 40 CFR 86.1370–2007(e)(1).

(ii) If you choose the ambient operating region specified in paragraph (e)(4)(ii) of this section, the temperature and humidity ranges for which correction factors are allowed are defined in 40 CFR 86.1370–2007(e)(2).

(6) For engines equipped with exhaust-gas recirculation, the NTE standards of this section do not apply during the cold operating conditions specified in 40 CFR 86.1370–2007(f).

(7) For engines certified to a PM FEL less than or equal to 0.01 g/kW-hr, the PM NTE standard is 0.02 g/kW-hr.

(f) *Fuel types.* The exhaust emission standards in this section apply for engines using the fuel type on which the engines in the engine family are designed to operate, except for engines certified under § 1039.615. For engines certified under § 1039.615, the standards of this section apply to emissions measured using the specified test fuel. You must meet the numerical emission standards for NMHC in this section based on the following types of hydrocarbon emissions for engines powered by the following fuels:

(1) Alcohol-fueled engines: THCE emissions.

(2) Other engines: NMHC emissions.

(g) *Useful life.* Your engines must meet the exhaust emission standards in paragraphs (a) through (e) of this section over their full useful life.

(1) The useful life values are shown in the following table, except as allowed by paragraph (g)(2) of this section:

TABLE 4 OF § 1039.101—USEFUL LIFE VALUES

If your engine is certified as . . .	And its maximum power is . . .	And its rated speed is . . .	Then its useful life is . . .
(i) Variable speed or constant speed.	kW <19	Any Speed	3,000 hours or five years, whichever comes first.
(ii) Constant speed	19 ≤ kW <37	3,000 rpm or higher	3,000 hours or five years, whichever comes first.
(iii) Constant speed	19 ≤ kW <37	Less than 3,000 rpm	5,000 hours or seven years, whichever comes first.
(iv) Variable	19 ≤ kW <37	Any Speed	5,000 hours or seven years, whichever comes first.
(v) Variable speed or constant speed.	kW ≥37	Any speed	8,000 hours or ten years, whichever comes first.

(2) You may request in your application for certification that we approve a shorter useful life for an engine family. We may approve a shorter useful life if we determine that these engines will rarely operate longer than the alternate useful life. Your demonstration must include documentation from in-use engines. Your demonstration must also include any overhaul interval that you recommend and any mechanical warranty that you offer for the engine.

(h) *Applicability for testing.* The emission standards in this subpart apply to all testing, including certification, selective enforcement audits, and in-use testing. For selective enforcement audits, we will require you to perform duty-cycle testing as specified in §§ 1039.505 and 1039.510. The NTE standards of this section apply for those tests. We will not direct you to do additional testing under a selective enforcement audit to show that your engines meet the NTE standards.

§ 1039.102 What exhaust emission standards and phase-in allowances apply for my engines in model year 2014 and earlier?

The exhaust emission standards of this section apply for 2014 and earlier model years. See § 1039.101 for exhaust emission standards that apply to later model years. See 40 CFR 89.112 for exhaust emission standards that apply to model years before the standards of this part 1039 take effect.

(a) *Emission standards for transient testing.* Transient exhaust emissions from your engines may not exceed the applicable emission standards in Tables 1 through 6 of this section. Measure emissions using the applicable transient test procedures described in subpart F of this part. See paragraph (c) of this section for a description of provisions related to the phase-in and phase-out standards shown in Tables 4 through 6 of this section. The emission standards for transient testing are limited for certain engines, as follows:

(1) The transient standards in this section do not apply for the following engines:

(i) Engines below 37 kW for model years before 2013.

(ii) Engines certified under Option #1 of Table 3 of this section. These are the small-volume manufacturer engines certified to the Option #1 standards for model years 2008 through 2015 under § 1039.104(c), and other engines certified to the Option #1 standards for model years 2008 through 2012.

(iii) Engines certified to an alternate FEL during the first four years of the Tier 4 standards for the applicable power category, as allowed in § 1039.104(g). However, you may certify these engines to the transient standards in this section to avoid using temporary compliance adjustment factors, as described in § 1039.104(g)(2). Note that in some cases this four-year period extends into the time covered by the standards in § 1039.101.

(iv) Constant-speed engines.

(v) Engines above 560 kW.

(2) The transient standards in this section for gaseous pollutants do not apply to phase-out engines that you certify to the same numerical standards (and FELs if the engines are certified using ABT) for gaseous pollutants as you certified under the Tier 3 requirements of 40 CFR part 89. However, except as specified by paragraph (a)(1) of this section, the transient PM emission standards apply to these engines.

(b) Emission standards for steady-state testing. Steady-state exhaust emissions from your engines may not exceed the applicable emission standards in Tables 1 through 7 of this section. Measure emissions using the applicable steady-state test procedures described in subpart F of this part. See paragraph (c) of this section for a description of provisions related to the phase-in and phase-out standards shown in Tables 4 through 6 of this section.

TABLE 1 OF § 1039.102.—TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): KW < 19

Maximum engine power	Model years	PM	NO_X + NMHC	CO
kW < 8	2008–2014	[1] 0.40	7.5	8.0
8 ≤ kW < 19	2008–2014	0.40	7.5	6.6

[1] For engines that qualify for the special provisions in § 1039.101(c), you may delay certifying to the standards in this part 1039 until 2010. In 2009 and earlier model years, these engines must instead meet the applicable Tier 2 standards and other requirements from 40 CFR part 89. Starting in 2010, these engines must meet a PM standard of 0.60 g/kW-hr, as described in § 1039.101(c). Engines certified to the 0.60 g/kWhr PM standard may not generate ABT credits.

TABLE 2 OF § 1039.102.—INTERIM TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): 19 ≤ KW < 37

Model years	PM	NO_X + NMHC	CO
2008–2012	0.30	7.5	5.5
2013–2014	0.03	4.7	5.5

TABLE 3 OF § 1039.102.—INTERIM TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): 37 ≤ KW < 56

Option [1]	Model years	PM	NO_X + NMHC	CO
#1	2008–2012	0.30	4.7	5.0
#2	2012	0.03	4.7	5.0
All	2013–2014	0.03	4.7	5.0

[1] You may certify engines to the Option #1 or Option #2 standards starting in the listed model year. Under Option #1, all engines at or above 37 kW and below 56 kW produced before the 2013 model year must meet the applicable Option #1 standards in this table. These engines are considered to be "Option #1 engines." Under Option #2, all these engines produced before the 2012 model year must meet the applicable standards under 40 CFR part 89. Engines certified to the Option #2 standards in model year 2012 are considered to be "Option #2 engines."

TABLE 4 OF § 1039.102.—INTERIM TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): 56 ≤ KW < 75

Model years [1]	Phase-in option	PM	NO_X	NMHC	NO_X + NMHC	CO
2012–2013	Phase-in	0.02	0.40	0.19		5.0
	Phase-out	0.02			4.7	5.0
2014	All engines	0.02	0.40	0.19		5.0

[1] See paragraph (d)(2) of this section for provisions that allow for a different phase-in schedule than that specified in paragraph (c)(1) of this section.

TABLE 5 OF § 1039.102.—INTERIM TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): 75 ≤ KW < 130

Model years [1]	Phase-in option	PM	NO_X	NMHC	NO_X + NMHC	CO
2012–2013	Phase-in	0.02	0.40	0.19		5.0
	Phase-out	0.02			4.0	5.0
2014	All engines	0.02	0.40	0.19		5.0

[1] See paragraph (d)(2) of this section for provisions that allow for a different phase-in schedule than that specified in paragraph (c)(1) of this section.

TABLE 6 OF § 1039.102.—INTERIM TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): 130 ≤ KW < 560

Model years [1]	Phase-in option	PM	NO_X	NMHC	NO_X + NMHC	CO
2011–2013	Phase-in	0.02	0.40	0.19		3.5
	Phase-out	0.02			4.0	3.5
2014	All engines	0.02	0.40	0.19		3.5

TABLE 7 OF § 1039.102.—INTERIM TIER 4 EXHAUST EMISSION STANDARDS (G/KW-HR): KW > 560

Model years	Maximum engine power	Application	PM	NO_X	NMHC	CO
2011–2014	560 < kW ≤ 900	All	0.10	3.5	0.40	3.5
	kW > 900	Generator sets	0.10	0.67	0.40	3.5
		All except generator sets	0.10	3.5	0.40	3.5

(c) *Phase-in requirements.* The following phase-in provisions apply for engines in 56–560 kW power categories meeting the interim Tier 4 standards in paragraphs (a) and (b) of this section:

(1) For each model year before 2014 noted in Tables 4 through 6 of this section, you must certify engine families representing at least 50 percent of your U.S.-directed production volume for each power category to the applicable phase-in standards, except as allowed by paragraph (c)(3), (d)(2), or (e) of this section. Any engines not certified to the phase-in standards must be certified to the corresponding phase-out standards.

(2) Engines certified to the phase-out standards in Tables 4 through 6 of this section must comply with all other requirements that apply to Tier 4 engines, except as otherwise specified in this section.

(3) At the time of certification, show how you intend to meet the phase-in requirements of this paragraph (c) based on projected U.S.-directed production volumes. If your actual U.S.-directed production volume fails to meet the phase-in requirements for a given model year, you must make up the shortfall (in terms of number of engines) by the end of the model year representing the final year of the phase-in period. For example, if you plan in good faith to produce 50 percent of a projected 10,000 engines in the 56–130 kW power category (*i.e.*, 5,000 engines) in 2012 in compliance with the Tier 4 phase-in standards for NO_X and NMHC in Table 4 of this section, but produce 4,500 such engines of an actual 10,000 engines, you must produce 500 engines in model year 2013 (*i.e.*, the final year of the phase-in for this power category) that meet the Tier 4 phase-in standards above and beyond the production otherwise needed to meet the 50-percent phase-in requirement for model year 2013. If any shortfall exceeds the applicable limit of paragraph (c)(3)(i) or (ii) of this section, that number of phase-out engines will be considered not covered by a certificate of conformity and in violation of § 1068.101(a)(1). The shortfall allowed by this paragraph (c)(3) may not exceed a certain number of engines, as follows:

(i) For engine families certified according to the alternate phase-in schedule described in paragraph (d)(2) of this section, for model years prior to the final year of the phase-in, 5 percent of your actual U.S.-directed production volume for that power category in that model year.

(ii) For all other engine families, for model years prior to the final year of the phase-in, 25 percent of your actual U.S.-directed production volume for that power category in that model year.

(iii) No shortfall is allowed in the final year of the phase-in.

(4) Engines you introduce into commerce beyond the limits described in paragraphs (c)(3) of this section will be considered not covered by a certificate of conformity and in violation of § 1068.101(a)(1).

(5) For the purposes of this part, the term "phase-in" means relating to a standard that is identified in this section as a phase-in standard and the term "phase-out" means relating to a standard that is identified in this section as a phase-out standard. For example, a 200–kW engine from the 2012 model year that is certified to the 4.0 g/kW-hr NO_X+NMHC standard in Table 6 of § 1039.102 is a phase-out engine.

(d) *Banked credits and alternate phase-in for 56–130 kW engines.* For engines in the 56–130 kW power category, you may use only one of the following additional provisions:

(1) For model years 2012 through 2014, you may use banked NO_X+NMHC credits from any Tier 2 engine at or above 37 kW certified under 40 CFR part 89 to meet the NO_X phase-in standards or the NO_X+NMHC phase-out standards under paragraphs (b) and (c) of this section, subject to the additional ABT provisions in § 1039.740.

(2) Instead of meeting the phase-in requirements of paragraph (c)(1) of this section, you may certify engine families representing at least 25 percent of your U.S.-directed production volume for each model year from 2012 through 2014 to the applicable phase-in standards in Tables 4 and 5 of this section, except as allowed by paragraph (c)(3) or (e) of this section. Any engines not certified to the phase-in standards must be certified to the corresponding phase-out standards. Engines certified under this paragraph (d)(2) may generate NO_X emission credits only for averaging within the same power category during the same model year.

For engines certified under this paragraph (d)(2), the 2014 model year may not extend beyond December 30, 2014.

(e) *Alternate NO_X standards.* For engines in 56–560 kW power categories during the phase-in of Tier 4 standards, you may certify engine families to the alternate NO_X standards in this paragraph (e) instead of the phase-in and phase-out NO_X and NO_X+NMHC standards described in Tables 4 through 6 of this section. Engines certified under this section must be certified to an NMHC standard of 0.19 g/kW-hr. Do not include engine families certified under this paragraph (e) in determining whether you comply with the percentage phase-in requirements of paragraphs (c) and (d)(2) of this section. Except for the provisions for alternate FEL caps in § 1039.104(g), the NO_X standards and FEL caps under this paragraph (e) are as follows:

(1) For engines in the 56–130 kW power category, apply the following alternate NO_X standards and FEL caps:

(i) If you use the provisions of paragraph (d)(1) of this section, your alternate NO_X standard for any engine family in the 56–130 kW power category is 2.3 g/kW-hr for model years 2012 and 2013. Engines certified to this standard may not exceed a NO_X FEL cap of 3.0 g/kW-hr.

(ii) If you use the provisions of paragraph (d)(2) of this section, your alternate NO_X standard for any engine family in the 56–130 kW power category is 3.4 g/kW-hr for model years 2012 through 2014. Engines below 75 kW certified to this standard may not exceed a NO_X FEL cap of 4.4 g/kW-hr; engines at or above 75 kW certified to this standard may not exceed a NO_X FEL cap of 3.8 g/kW-hr.

(iii) If you do not use the provisions of paragraph (d) of this section, you may apply the alternate NO_X standard and the appropriate FEL cap from either paragraph (e)(1)(i) or (ii) of this section.

(2) For engines in the 130–560 kW power category, the alternate NO_X standard is 2.0 g/kW-hr for model years 2011 through 2013. Engines certified to this standard may not exceed a NO_X FEL cap of 2.7 g/kW-hr.

(f) *Split families.* For generating or using credits for engines in 56–560 kW power categories during the phase-in of Tier 4 standards, you may split an engine family into two subfamilies (for example, one that uses credits and one that generates credits for the same pollutant).

(1) Identify any split engine families in your application for certification. Your engines must comply with all the standards and requirements applicable to Tier 4 engines, except as noted in this paragraph (f). You may calculate emission credits relative to different emission standards (*i.e.*, phase-in and phase-out standards) for different sets of engines within the engine family, but the engine family must be certified to a single set of standards and FELs. To calculate NO_X+NMHC emission credits, add the NO_X FEL to the NMHC phase-in standard for comparison with the applicable NO_X+NMHC phase-out standard. Any engine family certified under this paragraph (f) must meet the applicable phase-in standard for NMHC. You may assign the number and configurations of engines within the respective subfamilies any time before the due date for the final report required in § 1039.730. Apply the same label to each engine in the family, including the NO_X FEL to which it is certified.

(2) For example, a 10,000-unit engine family in the 75–130 kW power category may be certified to meet the standards for PM, NMHC, and CO that apply to phase-in engines, with a 0.8 g/kW-hr FEL for NO_X. When compared to the phase-out NO_X+NMHC standard, this engine family would generate positive NO_X+NMHC emission credits. When compared to the phase-in NO_X standard, this engine family would generate negative NO_X emission credits. You could create a subfamily with 2,500 engines (one-quarter of the 10,000 engines) and identify them as phase-in engines. You would count these 2,500, with their negative NO_X credits, in determining compliance with the 50-percent phase-in requirement in paragraph (c)(1) of this section. You would calculate negative credits relative to the 0.40 g/kW-hr NO_X standard for these 2,500 engines. You would identify the other 7,500 engines in the family as phase-out engines and calculate positive credits relative to the 4.0 g/kW-hr NO_X+NMHC standard.

(g) *Other provisions.* The provisions of § 1039.101(d) through (h) apply with respect to the standards of this section, with the following exceptions and special provisions:

(1) *NTE standards.* Use the provisions of § 1039.101(e)(3) to calculate and apply the NTE standards, but base these calculated values on the applicable standards in this section or the applicable FEL, instead of the standards in Table 1 of § 1039.101. All other provisions of § 1039.101(e) apply under this paragraph (g)(1). The NTE standards do not apply for certain engines and certain pollutants, as follows:

(i) All engines below 37 kW for model years before 2013.

(ii) All engines certified under Option #1 of Table 3 of this section. These are small-volume manufacturer engines certified to the Option #1 standards for model years 2008 through 2015 under § 1039.104(c), and other engines certified to the Option #1 standards for model years 2008 through 2012.

(iii) All engines less than or equal to 560 kW that are certified to an FEL under the alternate FEL program during the first four years of the Tier 4 standards for the applicable power category, as described in § 1039.104(g). However, if you apply to meet transient emission standards for these engines under § 1039.102(a)(1)(iii), you must also meet the NTE standards in this paragraph (g)(1).

(iv) Gaseous pollutants for phase-out engines that you certify to the same numerical standards and FELs for gaseous pollutants to which you certified under the Tier 3 requirements of 40 CFR part 89. However, the NTE standards for PM apply to these engines.

(2) *Interim FEL caps.* As described in 1039.101(d), you may participate in the ABT program in subpart H of this part by certifying engines to FELs for PM, NO_X, or NO_X+NMHC instead of the standards in Tables 1 through 7 of this section for the model years shown. The FEL caps listed in the following table apply instead of the FEL caps in§ 1039.101(d)(1), except as allowed by § 1039.104(g):

TABLE 8 OF § 1039.102.—INTERIM TIER 4 FEL CAPS, G/KW-HR

Maximum engine power	Phase-in option	Model years [1]	PM	NO_X	NO_X+NMHC
kW < 19		2008–2014	0.80		[2] 9.5
19 ≤ kW < 37		2008–2012	0.60		9.5
37 ≤ kW < 56		[3] 2008–2012	0.40		7.5
56 ≤ kW < 130	Phase-in	2012–2013	0.04	0.80	
56 ≤ kW < 130	Phase-out	2012–2013	0.04		[4] 6.6

TABLE 8 OF § 1039.102.—INTERIM TIER 4 FEL CAPS, G/KW-HR—Continued

Maximum engine power	Phase-in option	Model years [1]	PM	NO_X	NO_X+NMHC
130 ≤ kW ≤ 560	Phase-in	2011–2013	0.04	0.80	
130 ≤ kW ≤ 560	Phase-out	2011–2013	0.04		[5] 6.4
kW > 560		2011–2014	0.20	6.2	

[1] For model years before 2015 where this table does not specify FEL caps, apply the FEL caps shown in § 1039.101.
[2] For engines below 8 kW, the FEL cap is 10.5 g/kW-hr for NO_X+NMHC emissions.
[3] For manufacturers certifying engines to the standards of this part 1039 in 2012 under Option #2 of Table 3 of § 1039.102, the FEL caps of § 1039.101 apply for model year 2012 and later; see 40 CFR part 89 for provisions that apply to earlier model years.
[4] For engines below 75 kW, the FEL cap is 7.5 g/kW-hr for NO_X+NMHC emissions.
[5] For engines below 225 kW, the FEL cap is 6.6 g/kW-hr for NO_X+NMHC emissions.

(3) *Crankcase emissions.* The crankcase emission requirements of § 1039.115(a) do not apply to engines using charge-air compression that are certified to an FEL under the alternate FEL program in § 1039.104(g) during the first four years of the Tier 4 standards for the applicable power category.

(4) *Special provisions for 37–56 kW engines.* For engines at or above 37 kW and below 56 kW from model years 2008 through 2012, you must take the following additional steps:

(i) State the applicable PM standard on the emission control information label.

(ii) Add information to the emission-related installation instructions to clarify the equipment manufacturer's obligations under § 1039.104(f).

§ 1039.104 Are there interim provisions that apply only for a limited time?

The provisions in this section apply instead of other provisions in this part. This section describes when these interim provisions apply.

(a) *Incentives for early introduction.* This paragraph (a) allows you to reduce the number of engines subject to the applicable standards in § 1039.101 or § 1039.102, when some of your engines are certified to the specified levels earlier than otherwise required. The engines that are certified early are considered offset-generating engines. The provisions of this paragraph (a), which describe the requirements applicable to offset-generating engines, apply beginning in model year 2007. These offset generating engines may generate additional allowances for equipment manufacturers under the incentive program described in § 1039.627; you may instead use these offsets under paragraph (a)(2) of this section in some cases.

(1) For early-compliant engines to generate offsets for use either under this paragraph (a) or under § 1039.627, you must meet the following general provisions:

(i) You may not generate offsets from engines below 19 kW.

(ii) You must begin actual production of engines covered by the corresponding certificate by the following dates:

(A) For engines at or above 19 kW and below 37 kW: September 1, 2012.

(B) For engines at or above 37 kW and below 56 kW: September 1, 2012 if you choose Option #1 in Table 3 of § 1039.102, or September 1, 2011 if you do not choose Option #1 in Table 3 of § 1039.102.

(C) For engines in the 56–130 kW power category: September 1, 2011.

(D) For engines in the 130–560 kW power category: September 1, 2010.

(E) For engines above 560 kW: September 1, 2014.

(iii) Engines you produce after December 31 of the year shown in paragraph (a)(1)(ii) of this section may not generate offsets.

(iv) You may not use ABT credits to certify offset-generating engines.

(v) Offset-generating engines must be certified to the Tier 4 standards and requirements under this part 1039.

(2) If equipment manufacturers decline offsets for your offset-generating engines under § 1039.627, you may not generate ABT credits with these engines, but you may reduce the number of engines that are required to meet the standards in § 1039.101 or 1039.102 as follows:

For every . . .	With maximum engine power . . .	That are certified to the applicable standards in . . .	You may reduce the number of engines in the same power category that are required to meet the . . .	In later model years by . . .
(i) 2 engines	19 ≤ kW < 37	Table 2 of § 1039.102 [1]	PM standard in Table 2 of § 1039.102 applicable to model year 2013 or 2014 engines or the PM standard in Table 1 of § 1039.101.	3 engines.
(ii) 2 engines	56 ≤ kW ≤ 560	Table 4, 5, or 6 of § 1039.102 for Phase-out engines.	Phase-out standards in Tables 4 through 6 of § 1039.102.	3 engines.
(iii) 2 engines	kW ≥ 19	Table 1 of § 1039.101	Standards in Tables 2 through 7 of § 1039.102 or standards in Table 1 of § 1039.101.	3 engines.[2]
(iv) 1 engine	kW ≥ 19	Table 1 of § 1039.101 + 0.20 g/kW-hr NO_X standard.	Standards in Tables 2 through 7 of § 1039.102 or standards in Table 1 of § 1039.101.	2 engines.[2]

[1] The engine must be certified to the PM standard applicable to model year 2013 engines, and to the NO_X+NMHC and CO standards applicable to model year 2012 engines.
[2] For engines above 560 kW, offsets from generator-set engines may be used only for generator-set engines. Offsets from engines for other applications may be used only for other applications besides generator sets.

(3) Example: If you produce 100 engines in the 56–130 kW power category in model year 2008 that are certified to the 56–130 kW standards listed in § 1039.101, and you produced 10,000 engines in this power category in

model year 2015, then only 9,850 of these model year 2015 engines would need to comply with the standards listed in § 1039.101. The 100 offset-generating engines in model year 2008 could not use or generate ABT credits.

(4) Offset-using engines (that is, those not required to certify to the standards of § 1039.101 or § 1039.102 under paragraph (a)(2) of this section) are subject to the following provisions:

(i) If the offset is being used under paragraph (a)(2)(i) of this section for an engine that would otherwise be certified to the model year 2013 or 2014 standards in Table 2 of § 1039.102 or the standards in Table 1 of § 1039.101, this engine must be certified to the standards and requirements of this part 1039, except that the only PM standard that applies is the steady-state PM standard that applies for model year 2012. Such an engine may not generate ABT credits.

(ii) If the offset is being used under paragraph (a)(2)(ii) of this section for an engine that would otherwise be certified to the phase-out standards in Tables 4 through 6 of § 1039.102, this engine must be certified to the standards and requirements of this part 1039, except that the PM standard is the Tier 3 PM standard that applies for this engine's maximum power. Such an engine will be treated as a phase-out engine for purposes of determining compliance with percentage phase-in requirements. Such an engine may not generate ABT credits.

(iii) All other offset-using engines must meet the standards and other provisions that apply in model year 2011 for engines in the 19–130 kW power categories, in model year 2010 for engines in the 130–560 kW power category, or in model year 2014 for engines above 560 kW. Show that engines meet these emission standards by meeting all the requirements of § 1039.260. You must meet the labeling requirements in § 1039.135, but add the following statement instead of the compliance statement in § 1039.135(c)(12): "THIS ENGINE MEETS U.S. EPA EMISSION STANDARDS UNDER 40 CFR 1039.104(a)." For power categories with a percentage phase-in, these engines should be treated as phase-in engines for purposes of determining compliance with phase-in requirements.

(5) If an equipment manufacturer claims offsets from your engine for use under § 1039.627, the engine generating the offset must comply with the requirements of paragraph (a)(1) of this section. You may not generate offsets for use under paragraphs (a)(2) and (5) of this section for these engines. You may generate ABT credits from these engines as follows:

(i) To generate emission credits for NO_X, NO_X+NMHC, and PM, the engine must be certified to FELs at or below the standards in paragraph (a)(2) of this section.

(ii) Calculate credits according to § 1039.705 but use as the applicable standard the numerical value of the standard to which the engine would have otherwise been subject if it had not been certified under this paragraph (a).

(iii) For the production volume, use the number of engines certified under this paragraph (a) for which you do not claim offsets under paragraph (a)(2) of this section.

(6) You may include engines used to generate offsets under this paragraph (a) and engines used to generate offsets under § 1039.627 in the same engine family, subject to the provisions of § 1039.230. The engine must be certified to FELs, as specified in paragraph (a)(5)(i) of this section. The FELs must be below the standard levels specified in paragraph (a)(2) of this section and those specified in § 1039.627. In the reports required in § 1039.730, include the following information for each model year:

(i) The total number of engines that generate offsets under this paragraph (a).

(ii) The number of engines used to generate offsets under paragraph (a)(2) of this section.

(iii) The names of equipment manufacturers that intend to use your offsets under § 1039.627 and the number of offsets involved for each equipment manufacturer.

(b) *In-use compliance limits*. For purposes of determining compliance after title or custody has transferred to the ultimate purchaser, calculate the applicable in-use compliance limits by adjusting the applicable standards or FELs. This applies only for engines at or above 19 kW. The NO_X adjustment applies only for engines with a NO_X FEL no higher than 2.1 g/kW-hr The PM adjustment applies only for engines with a PM FEL no higher than the PM standard in § 1039.101 for the appropriate power category. Add the following adjustments to the otherwise applicable standards or FELs (steady-state, transient, and NTE) for NO_X and PM:

In model years . . .	If your engine's maximum power is . . .	The NO_X adjustment in g/kW-hr is . . .	The PM adjustment in g/kW-hr is . . .
2013–2014	19 ≤ kW < 56	not allowed	0.01
2012–2016	56 ≤ kW < 130	0.16 for operating hours ≤ 2000	0.01
		0.25 for operating hours 2001 to 3400	
		0.34 for operating hours > 3400	
2011–2015	130 ≤ kW < 560	0.16 for operating hours ≤ 2000	0.01
		0.25 for operating hours 2001 to 3400	
		0.34 for operating hours > 3400	
2011–2016	kW > 560	0.16 for operating hours ≤ 2000	0.01
		0.25 for operating hours 2001 to 3400	
		0.34 for operating hours > 3400	

(c) *Provisions for small-volume manufacturers*. Special provisions apply if you are a small-volume engine manufacturer subject to the requirements of this part. You must notify us in writing before January 1, 2008 if you intend to use these provisions.

(1) You may delay complying with certain otherwise applicable Tier 4 emission standards and requirements as described in the following table:

If your engine's maximum power is . . .	You may delay meeting . . .	Until model year . . .	Before that model year the engine must comply with . . .
kW < 19	The standards and requirements of this part	2011	The standards and requirements in 40 CFR part 89.
19 ≤ kW < 37	The Tier 4 standards and requirements of this part that would otherwise be applicable in model year 2013.	2016	The Tier 4 standards and requirements that apply for model year 2008.
37 ≤ kW < 56	See paragraph (c)(2) of this section for special provisions that apply for engines in this power category.		
56 ≤ kW < 130	The standards and requirements of this part	2015	The standards and requirements in 40 CFR part 89.

(2) To use the provisions of this paragraph (c) for engines at or above 37 kW and below 56 kW, choose one of the following:

(i) If you comply with the 0.30 g/kW-hr PM standard in § 1039.102 in all model years from 2008 through 2012 without using PM credits, you may continue meeting that standard through 2015.

(ii) If you do not choose to comply with paragraph (c)(2)(i) of this section, you may continue to comply with the standards and requirements in 40 CFR part 89 for model years through 2012, but you must begin complying in 2013 with Tier 4 standards and requirements specified in Table 3 of § 1039.102 for model years 2013 and later.

(3) After the delays indicated in paragraph (c)(1) and (2) of this section, you must comply with the same Tier 4 standards and requirements as all other manufacturers.

(4) For engines not in the 19–56 kW power category, if you delay compliance with any standards under this paragraph (c), you must do all the following things for the model years when you are delaying compliance with the otherwise applicable standards:

(i) Produce engines that meet all the emission standards and other requirements under 40 CFR part 89 applicable for that model year, except as noted in this paragraph (c).

(ii) Meet the labeling requirements in 40 CFR 89.110, but use the following compliance statement instead of the compliance statement in 40 CFR 89.110(b)(10): "THIS ENGINE COMPLIES WITH U.S. EPA REGULATIONS FOR [CURRENT MODEL YEAR] NONROAD COMPRESSION-IGNITION ENGINES UNDER 40 CFR 1039.104(c).".

(iii) Notify the equipment manufacturer that the engines you produce under this section are excluded from the production volumes associated with the equipment-manufacturer allowance program in § 1039.625.

(5) For engines in the 19–56 kW power category, if you delay compliance with any standards under this paragraph (c), you must do all the following things for the model years when you are delaying compliance with the otherwise applicable standards:

(i) Produce engines in those model years that meet all the emission standards and other requirements that applied for your model year 2008 engines in the same power category.

(ii) Meet the labeling requirements in § 1039.135, but use the following compliance statement instead of the compliance statement in § 1039.135: "THIS ENGINE COMPLIES WITH U.S. EPA REGULATIONS FOR [CURRENT MODEL YEAR] NONROAD COMPRESSION-IGNITION ENGINES UNDER 40 CFR 1039.104(c).".

(iii) Notify the equipment manufacturer that the engines you produce under this section are excluded from the production volumes associated with the equipment-manufacturer allowance program in § 1039.625.

(6) The provisions of this paragraph (c) may not be used to circumvent the requirements of this part.

(d) *Deficiencies for NTE standards.* You may ask us to accept as compliant an engine that does not fully meet specific requirements under the applicable NTE standards. Such deficiencies are intended to allow for minor deviations from the NTE standards under limited conditions. We expect your engines to have functioning emission-control hardware that allows you to comply with the NTE standards.

(1) Request our approval for specific deficiencies in your application for certification, or before you submit your application. We will not approve deficiencies retroactively to cover engines already certified. In your request, identify the scope of each deficiency and describe any auxiliary emission-control devices you will use to control emissions to the lowest practical level, considering the deficiency you are requesting.

(2) We will approve a deficiency only if compliance would be infeasible or unreasonable considering such factors as the technical feasibility of the given hardware and the applicable lead time and production cycles—including schedules related to phase-in or phase-out of engines. We may consider other relevant factors.

(3) Our approval applies only for a single model year and may be limited to specific engine configurations. We may approve your request for the same deficiency in the following model year if correcting the deficiency would require unreasonable hardware or software modifications and we determine that you have demonstrated an acceptable level of effort toward complying.

(4) You may ask for any number of deficiencies in the first three model years during which NTE standards apply for your engines. For the next four model years, we may approve up to three deficiencies per engine family. Deficiencies of the same type that apply similarly to different power ratings within a family count as one deficiency per family. We may condition approval of any such additional deficiencies during these four years on any additional conditions we determine to be appropriate. We will not approve deficiencies after the seven-year period specified in this paragraph (d)(4).

(e) *Diesel test fuels and corresponding labeling requirements.* For diesel-fueled engines in 2011 and later model years, the diesel test fuel is ultra low-sulfur diesel fuel specified in 40 CFR part 1065. For diesel-fueled engines in 2010 and earlier model years, use test fuels and meet labeling requirements as follows:

(1) Use the following test fuels in 2010 and earlier model years:

(i) Unless otherwise specified, the diesel test fuel is low-sulfur diesel fuel specified in 40 CFR part 1065.

(ii) In model years 2007 through 2010, you may use ultra low-sulfur diesel fuel as the test fuel for any engine family that employs sulfur-sensitive technology if you can demonstrate that in-use engines in the family will use diesel fuel with a sulfur concentration no greater than 15 ppm.

(iii) You may use ultra low-sulfur diesel fuel as the test fuel for engine families in any power category below 56 kW, as long as none of the engines in your engine family employ sulfur-sensitive technologies, you ensure that ultimate purchasers of equipment using these engines are informed that ultra low-sulfur diesel fuel is recommended, and you recommend to equipment manufacturers that a label be applied at the fuel inlet recommending 15 ppm fuel.

(iv) For the engines described in § 1039.101(c) that are certified to the 0.60 g/kW-hr PM standard in Table 1 of § 1039.102 in the 2010 model year, you may test with the ultra low-sulfur fuel specified in 40 CFR part 1065.

(2) Meet the labeling requirements of this paragraph (e)(2) (or other labeling requirements we approve) to identify the applicable test fuels specified in paragraph (e)(1) of this section. Provide instructions to equipment manufacturers to ensure that they are aware of these labeling requirements.

(i) For engines certified under the provisions of paragraph (e)(1)(i) of this section, include the following statement on the emission control information label and the fuel-inlet label specified in § 1039.135: "LOW SULFUR FUEL OR ULTRA LOW SULFUR FUEL ONLY".

(ii) For engines certified under the provisions of paragraph (e)(1)(ii) of this section, include the following statement on the emission control information label and the fuel-inlet label specified in § 1039.135: "ULTRA LOW SULFUR FUEL ONLY".

(iii) For engines certified under the provisions of paragraph (e)(1)(iii) of this section, include the following statement on the emission control information label specified in § 1039.135: "ULTRA LOW SULFUR FUEL RECOMMENDED".

(3) For model years 2010 and earlier, we will use the test fuel that you use under paragraph (e)(1) of this section, subject to the conditions of paragraph (e)(1) of this section.

(f) *Requirements for equipment manufacturers.* If you produce equipment with engines certified to Tier 3 standards under Option #2 of Table 3 of § 1039.102 during model years from 2008 through 2011, then a minimum number of pieces of equipment you produce using 2012 model year engines must have engines certified to the Option #2 standards, as follows:

(1) For equipment you produce with 2012 model year engines at or above 37 kW and below 56 kW, determine the minimum number of these engines that must be certified to the Option #2 standards in Table 3 of § 1039.102 as follows:

(i) If all the equipment you produce using 2008 through 2011 model year engines use engines certified to Tier 3 standards under Option #2 of Table 3 of § 1039.102, then all the 2012 model year engines you install must be certified to the Option #2 standards of Table 3 of § 1039.102.

(ii) If you produce equipment using 2008 through 2011 model year engines with some engines certified to Option #1 standards of Table 3 of § 1039.102 and some engines certified to Tier 3 standards under Option #2 standards of Table 3 of § 1039.102, calculate the minimum number of 2012 model year engines you must install that are certified to the Option #2 standards of Table 3 of § 1039.102 from the following equation:

$$\text{Minimum number} = [(T - O_1 - F)/(T - F) - 0.05] \times P$$

Where:

T = The total number of 2008–2010 model year engines at or above 37 kW and below 56 kW that you use in equipment you produce.

O_1 = The number of engines from the 2008–2010 model years certified under Option #1 of Table 3 of § 1039.102 that you use in equipment you produce.

F = The number of 2008–2010 model year engines at or above 37 kW and below 56 kW that you use in equipment you produce under the flexibility provisions of § 1039.625.

P = The total number of 2012 model year engines at or above 37 kW and below 56 kW that you use in equipment you produce.

(2) As needed for the calculation required by this paragraph (f), keep records of all equipment you produce using 2008–2012 model year engines at or above 37 kW and below 56 kW. If you fail to keep these records, you may not use any 2012 model year engines certified to Option #1 standards in your equipment.

(3) If you fail to comply with the provisions of this paragraph (f), then using 2012 model year engines certified under Option #1 of Table 3 of § 1039.102 (or certified to less stringent standards) in such equipment violates the prohibitions in § 1068.101(a)(1).

(g) *Alternate FEL caps.* You may certify a limited number of engines from your U.S.-directed production volume to the FEL caps in Table 1 of this section instead of the otherwise applicable FEL caps in § 1039.101(d)(1), § 1039.102(e), or § 1039.102(g)(2), subject to the following provisions:

(1) The provisions of this paragraph (g) apply during the model years shown in Table 1 of this section. During this period, the number of engines certified to the FEL caps in Table 1 of this section must not exceed 20 percent in any single model year in each power category. The sum of percentages over the four-year period must not exceed a total of 40 percent in each power category. If you certify an engine under an alternate FEL cap in this paragraph (g) for any pollutant, count it toward the allowed percentage of engines certified to the alternate FEL caps.

(2) If your engine is not certified to transient emission standards under the provisions of § 1039.102(a)(1)(iii), you must adjust your FEL upward by a temporary compliance adjustment factor (TCAF) before calculating your negative emission credits under § 1039.705, as follows:

(i) The temporary compliance adjustment factor for NO_X is 1.1.

(ii) The temporary compliance adjustment factor for PM is 1.5.

(iii) The adjusted FEL (FEL_{adj}) for calculating emission credits is determined from the steady-state FEL (FEL_{ss}) using the following equation:

$$FEL_{adj} = (FEL_{ss}) \times (TCAF)$$

(iv) The unadjusted FEL (FEL_{ss}) applies for all purposes other than credit calculation.

(3) These alternate FEL caps may not be used for phase-in engines.

(4) Do not apply TCAFs to gaseous emissions for phase-out engines that you certify to the same numerical standards (and FELs if the engines are certified using ABT) for gaseous pollutants as you certified under the Tier 3 requirements of 40 CFR part 89.

TABLE 1 OF § 1039.104.—ALTERNATE FEL CAPS

Maximum engine power	PM FEL cap, g/kW-hr	Model years for the alternate PM FEL cap	NO_X FEL cap, g/kW-hr	Model years for the alternate NO_X FEL cap
$19 \leq kW < 56$	0.30	[1] 2012–2015		
$56 \leq kW < 130$ [2]	0.30	[3] 2012–2015	3.8	[3] 2014–2015
$130 \leq kW \leq 560$	0.20	2011–2014	3.8	2014

TABLE 1 OF § 1039.104.—ALTERNATE FEL CAPS—Continued

Maximum engine power	PM FEL cap, g/kW-hr	Model years for the alternate PM FEL cap	NO_X FEL cap, g/kW-hr	Model years for the alternate NO_X FEL cap
kW > 560 [4]	0.10	2015–2018	3.5	2015–2018

[1] For manufacturers certifying engines under Option #1 of Table 3 of § 1039.102, these alternate FEL caps apply for model years from 2013 through 2016.
[2] For engines below 75 kW, the FEL caps are 0.40 g/kW-hr for PM emissions and 4.4 g/kW-hr for NO_X emissions.
[3] For engines certified under the provisions of § 1039.102(d)(2) or (e)(1)(ii), the alternate NO_X FEL cap in the table applies only for the 2015 model year.
[4] For engines above 560 kW, the provision for alternate NO_X FEL caps is limited to generator-set engines. For example, if you produce 1,000 generator-set engines above 560 kW in 2015, up to 200 of them may be certified to the alternate NO_X FEL caps.

§ 1039.105 What smoke standards must my engines meet?

(a) The smoke standards in this section apply to all engines subject to emission standards under this part, except for the following engines:
(1) Single-cylinder engines.
(2) Constant-speed engines.
(3) Engines certified to a PM emission standard or FEL of 0.07 g/kW-hr or lower.
(b) Measure smoke as specified in § 1039.501(c). Smoke from your engines may not exceed the following standards:
(1) 20 percent during the acceleration mode.
(2) 15 percent during the lugging mode.
(3) 50 percent during the peaks in either the acceleration or lugging modes.

§ 1039.107 What evaporative emission standards and requirements apply?

There are no evaporative emission standards for diesel-fueled engines, or engines using other nonvolatile or nonliquid fuels (for example, natural gas). If your engine uses a volatile liquid fuel, such as methanol, you must meet the evaporative emission requirements of 40 CFR part 1048 that apply to spark-ignition engines, as follows:
(a) Follow the steps in 40 CFR 1048.245 to show that you meet the requirements of 40 CFR 1048.105.
(b) Do the following things in your application for certification:
(1) Describe how your engines control evaporative emissions.
(2) Present test data to show that equipment using your engines meets the evaporative emission standards we specify in this section if you do not use design-based certification under 40 CFR 1048.245. Show these figures before and after applying deterioration factors, where applicable.

§ 1039.110 [Reserved]

§ 1039.115 What other requirements must my engines meet?

Engines subject to this part must meet the following requirements, except as noted elsewhere in this part:
(a) *Crankcase emissions.* Crankcase emissions may not be discharged directly into the ambient atmosphere from any engine, except as follows:
(1) Engines may discharge crankcase emissions to the ambient atmosphere if the emissions are added to the exhaust emissions (either physically or mathematically) during all emission testing.
(2) If you take advantage of this exception, you must do the following things:
(i) Manufacture the engines so that all crankcase emissions can be routed into the applicable sampling systems specified in 40 CFR part 1065.
(ii) Account for deterioration in crankcase emissions when determining exhaust deterioration factors.
(3) For purposes of this paragraph (a), crankcase emissions that are routed to the exhaust upstream of exhaust aftertreatment during all operation are not considered to be discharged directly into the ambient atmosphere.
(b)–(d) [Reserved]
(e) *Adjustable parameters.* Engines that have adjustable parameters must meet all the requirements of this part for any adjustment in the physically adjustable range. An operating parameter is not considered adjustable if you permanently seal it or if it is not normally accessible using ordinary tools. We may require that you set adjustable parameters to any specification within the adjustable range during any testing, including certification testing, selective enforcement auditing, or in-use testing.
(f) *Prohibited controls.* You may not design your engines with emission-control devices, systems, or elements of design that cause or contribute to an unreasonable risk to public health, welfare, or safety while operating. For example, this would apply if the engine emits a noxious or toxic substance it would otherwise not emit that contributes to such an unreasonable risk.
(g) *Defeat devices.* You may not equip your engines with a defeat device. A defeat device is an auxiliary emission-control device that reduces the effectiveness of emission controls under conditions that the engine may reasonably be expected to encounter during normal operation and use. This does not apply to auxiliary-emission control devices you identify in your certification application if any of the following is true:
(1) The conditions of concern were substantially included in the applicable test procedures described in subpart F of this part.
(2) You show your design is necessary to prevent engine (or equipment) damage or accidents.
(3) The reduced effectiveness applies only to starting the engine.

§ 1039.120 What emission-related warranty requirements apply to me?

(a) *General requirements.* You must warrant to the ultimate purchaser and each subsequent purchaser that the new nonroad engine, including all parts of its emission-control system, meets two conditions:
(1) It is designed, built, and equipped so it conforms at the time of sale to the ultimate purchaser with the requirements of this part.
(2) It is free from defects in materials and workmanship that may keep it from meeting these requirements.
(b) *Warranty period.* Your emission-related warranty must be valid for at least as long as the minimum warranty periods listed in this paragraph (b) in hours of operation and years, whichever comes first. You may offer an emission-related warranty more generous than we require. The emission-related warranty for the engine may not be shorter than any published warranty you offer without charge for the engine. Similarly, the emission-related warranty for any component may not be shorter than any published warranty you offer without charge for that component. If you provide an extended warranty to individual owners for any components covered in paragraph

(c) of this section for an additional charge, your emission-related warranty must cover those components for those owners to the same degree. If an engine has no hour meter, we base the warranty periods in this paragraph (b) only on the engine's age (in years). The warranty period begins when the engine is placed into service. The minimum warranty periods are shown in the following table:

If your engine is certified as . . .	And its maximum power is . . .	And its rated speed is . . .	Then its warranty period is . . .
Variable speed or constant speed.	kW < 19	Any speed	1,500 hours or two years, whichever comes first.
Constant speed	19 ≤ kW < 37	3,000 rpm or higher	1,500 hours or two years, whichever comes first.
Constant speed	19 ≤ kW < 37	Less than 3,000 rpm	3,000 hours or five years, whichever comes first.
Variable speed	19 ≤ kW < 37	Any speed	3,000 hours or five years, whichever comes first.
Variable speed or constant speed.	kW ≥ 37	Any speed	3,000 hours or five years, whichever comes first.

(c) *Components covered.* The emission-related warranty covers all components whose failure would increase an engine's emissions of any pollutant. This includes components listed in 40 CFR part 1068, Appendix I, and components from any other system you develop to control emissions. The emission-related warranty covers these components even if another company produces the component. Your emission-related warranty does not cover components whose failure would not increase an engine's emissions of any pollutant.

(d) *Limited applicability.* You may deny warranty claims under this section if the operator caused the problem through improper maintenance or use, as described in 40 CFR 1068.115.

(e) *Owners manual.* Describe in the owners manual the emission-related warranty provisions from this section that apply to the engine.

§ 1039.125 What maintenance instructions must I give to buyers?

Give the ultimate purchaser of each new nonroad engine written instructions for properly maintaining and using the engine, including the emission-control system. The maintenance instructions also apply to service accumulation on your emission-data engines, as described in § 1039.245 and in 40 CFR part 1065.

(a) *Critical emission-related maintenance.* Critical emission-related maintenance includes any adjustment, cleaning, repair, or replacement of critical emission-related components. This may also include additional emission-related maintenance that you determine is critical if we approve it in advance. You may schedule critical emission-related maintenance on these components if you meet the following conditions:

(1) You demonstrate that the maintenance is reasonably likely to be done at the recommended intervals on in-use engines. We will accept scheduled maintenance as reasonably likely to occur if you satisfy any of the following conditions:

(i) You present data showing that, if a lack of maintenance increases emissions, it also unacceptably degrades the engine's performance.

(ii) You present survey data showing that at least 80 percent of engines in the field get the maintenance you specify at the recommended intervals.

(iii) You provide the maintenance free of charge and clearly say so in maintenance instructions for the customer.

(iv) You otherwise show us that the maintenance is reasonably likely to be done at the recommended intervals.

(2) For engines below 130 kW, you may not schedule critical emission-related maintenance more frequently than the following minimum intervals, except as specified in paragraphs (a)(4), (b), and (c) of this section:

(i) For EGR-related filters and coolers, PCV valves, and fuel injector tips (cleaning only), the minimum interval is 1,500 hours.

(ii) For the following components, including associated sensors and actuators, the minimum interval is 3000 hours: fuel injectors, turbochargers, catalytic converters, electronic control units, particulate traps, trap oxidizers, components related to particulate traps and trap oxidizers, EGR systems (including related components, but excluding filters and coolers), and other add-on components. For particulate traps, trap oxidizers, and components related to either of these, maintenance is limited to cleaning and repair only.

(3) For engines at or above 130 kW, you may not schedule critical emission-related maintenance more frequently than the following minimum intervals, except as specified in paragraphs (a)(4), (b), and (c) of this section:

(i) For EGR-related filters and coolers, PCV valves, and fuel injector tips (cleaning only), the minimum interval is 1,500 hours.

(ii) For the following components, including associated sensors and actuators, the minimum interval is 4500 hours: fuel injectors, turbochargers, catalytic converters, electronic control units, particulate traps, trap oxidizers, components related to particulate traps and trap oxidizers, EGR systems (including related components, but excluding filters and coolers), and other add-on components. For particulate traps, trap oxidizers, and components related to either of these, maintenance is limited to cleaning and repair only.

(4) If your engine family has an alternate useful life under § 1039.101(g) that is shorter than the period specified in paragraph (a)(2) or (a)(3) of this section, you may not schedule critical emission-related maintenance more frequently than the alternate useful life, except as specified in paragraph (c) of this section.

(b) *Recommended additional maintenance.* You may recommend any additional amount of maintenance on the components listed in paragraph (a) of this section, as long as you state clearly that these maintenance steps are not necessary to keep the emission-related warranty valid. If operators do the maintenance specified in paragraph (a) of this section, but not the recommended additional maintenance, this does not allow you to disqualify those engines from in-use testing or deny a warranty claim. Do not take these maintenance steps during service accumulation on your emission-data engines.

(c) *Special maintenance.* You may specify more frequent maintenance to address problems related to special situations, such as atypical engine operation. You must clearly state that this additional maintenance is associated with the special situation you are addressing.

(d) *Noncritical emission-related maintenance.* You may schedule any amount of emission-related inspection or maintenance that is not covered by paragraph (a) of this section, as long as you state in the owners manual that these steps are not necessary to keep the emission-related warranty valid. If operators fail to do this maintenance, this does not allow you to disqualify those engines from in-use testing or deny a warranty claim. Do not take these inspection or maintenance steps during service accumulation on your emission-data engines.

(e) *Maintenance that is not emission-related.* For maintenance unrelated to emission controls, you may schedule any amount of inspection or maintenance. You may also take these inspection or maintenance steps during service accumulation on your emission-data engines, as long as they are reasonable and technologically necessary. This might include adding engine oil, changing air, fuel, or oil filters, servicing engine-cooling systems, and adjusting idle speed, governor, engine bolt torque, valve lash, or injector lash. You may perform this nonemission-related maintenance on emission-data engines at the least frequent intervals that you recommend to the ultimate purchaser (but not the intervals recommended for severe service).

(f) *Source of parts and repairs.* State clearly on the first page of your written maintenance instructions that a repair shop or person of the owner's choosing may maintain, replace, or repair emission-control devices and systems. Your instructions may not require components or service identified by brand, trade, or corporate name. Also, do not directly or indirectly condition your warranty on a requirement that the equipment be serviced by your franchised dealers or any other service establishments with which you have a commercial relationship. You may disregard the requirements in this paragraph (f) if you do one of two things:

(1) Provide a component or service without charge under the purchase agreement.

(2) Get us to waive this prohibition in the public's interest by convincing us the engine will work properly only with the identified component or service.

(g) *Payment for scheduled maintenance.* Owners are responsible for properly maintaining their engines. This generally includes paying for scheduled maintenance. However, manufacturers must pay for scheduled maintenance if it meets all the following criteria:

(1) Each affected component was not in general use on similar engines before the applicable dates shown in paragraph (6) of the definition of *new nonroad engine* in § 1039.801.

(2) The primary function of each affected component is to reduce emissions.

(3) The cost of the scheduled maintenance is more than 2 percent of the price of the engine.

(4) Failure to perform the maintenance would not cause clear problems that would significantly degrade the engine's performance.

(h) *Owners manual.* Explain the owner's responsibility for proper maintenance in the owners manual.

§ 1039.130 What installation instructions must I give to equipment manufacturers?

(a) If you sell an engine for someone else to install in a piece of nonroad equipment, give the engine installer instructions for installing it consistent with the requirements of this part. Include all information necessary to ensure that an engine will be installed in its certified configuration.

(b) Make sure these instructions have the following information:

(1) Include the heading: "Emission-related installation instructions".

(2) State: "Failing to follow these instructions when installing a certified engine in a piece of nonroad equipment violates federal law (40 CFR 1068.105(b)), subject to fines or other penalties as described in the Clean Air Act.".

(3) Describe the instructions needed to properly install the exhaust system and any other components consistent with the requirements of § 1039.205(u).

(4) [Reserved]

(5) Describe any limits on the range of applications needed to ensure that the engine operates consistently with your application for certification. For example, if your engines are certified only for constant-speed operation, tell equipment manufacturers not to install the engines in variable-speed applications.

(6) Describe any other instructions to make sure the installed engine will operate according to design specifications in your application for certification. This may include, for example, instructions for installing aftertreatment devices when installing the engines.

(7) State: "If you install the engine in a way that makes the engine's emission control information label hard to read during normal engine maintenance, you must place a duplicate label on the equipment, as described in 40 CFR 1068.105.".

(8) Describe equipment-labeling requirements consistent with § 1039.135. State whether you are providing the label for the fuel inlet or the equipment manufacturer must provide the label.

(c) You do not need installation instructions for engines you install in your own equipment.

(d) Provide instructions in writing or in an equivalent format. For example, you may post instructions on a publicly available website for downloading or printing. If you do not provide the instructions in writing, explain in your application for certification how you will ensure that each installer is informed of the installation requirements.

§ 1039.135 How must I label and identify the engines I produce?

(a) Assign each engine a unique identification number and permanently affix, engrave, or stamp it on the engine in a legible way.

(b) At the time of manufacture, affix a permanent and legible label identifying each engine. The label must be—

(1) Attached in one piece so it is not removable without being destroyed or defaced. However, you may use two-piece labels for engines below 19 kW if there is not enough space on the engine to apply a one-piece label.

(2) Secured to a part of the engine needed for normal operation and not normally requiring replacement.

(3) Durable and readable for the engine's entire life.

(4) Written in English.

(c) The label must—

(1) Include the heading "EMISSION CONTROL INFORMATION".

(2) Include your full corporate name and trademark. You may identify another company and use its trademark instead of yours if you comply with the provisions of § 1039.640.

(3) Include EPA's standardized designation for the engine family (and subfamily, where applicable).

(4) State the power category or subcategory from § 1039.101 or § 1039.102 that determines the applicable emission standards for the engine family.

(5) State the engine's displacement (in liters); however, you may omit this from the label if all the engines in the engine family have the same per-cylinder displacement and total displacement.

(6) State the date of manufacture [MONTH and YEAR]. You may omit this from the label if you keep a record of the engine-manufacture dates and provide it to us upon request.

(7) State the FELs to which the engines are certified if certification depends on the ABT provisions of subpart H of this part.

(8) Identify the emission-control system. Use terms and abbreviations consistent with SAE J1930 (incorporated by reference in § 1039.810). You may omit this information from the label if there is not enough room for it and you put it in the owners manual instead.

(9) For diesel-fueled engines, unless otherwise specified in § 1039.104(e)(2), state: "ULTRA LOW SULFUR FUEL ONLY'.

(10) Identify any additional requirements for fuel and lubricants that do not involve fuel-sulfur levels. You may omit this information from the label if there is not enough room for it and you put it in the owners manual instead.

(11) State the useful life for your engine family if we approve a shortened useful life under § 1039.101(g)(2).

(12) State: "THIS ENGINE COMPLIES WITH U.S. EPA REGULATIONS FOR [MODEL YEAR] NONROAD DIESEL ENGINES.".

(13) For engines above 560 kW, include the following things:

(i) For engines certified to the emission standards for generator-set engines, add the phrase "FOR GENERATOR SETS AND OTHER APPLICATIONS".

(ii) For all other engines, add the phrase "NOT FOR USE IN A GENERATOR SET".

(14) If your engines are certified only for constant-speed operation, state "USE IN CONSTANT-SPEED APPLICATIONS ONLY".

(d) You may add information to the emission control information label to identify other emission standards that the engine meets or does not meet (such as European standards). You may also add other information to ensure that the engine will be properly maintained and used.

(e) Except as specified in § 1039.104(e)(2), create a separate label with the statement: "ULTRA LOW SULFUR FUEL ONLY". Permanently attach this label to the equipment near the fuel inlet or, if you do not manufacture the equipment, take one of the following steps to ensure that the equipment will be properly labeled:

(1) Provide the label to the equipment manufacturer and include the appropriate information in the emission-related installation instructions.

(2) Confirm that the equipment manufacturers install their own complying labels.

(f) You may ask us to approve modified labeling requirements in this part 1039 if you show that it is necessary or appropriate. We will approve your request if your alternate label is consistent with the requirements of this part.

(g) If you obscure the engine label while installing the engine in the equipment, you must place a duplicate label on the equipment. If others install your engine in their equipment in a way that obscures the engine label, we require them to add a duplicate label on the equipment (see 40 CFR 1068.105); in that case, give them the number of duplicate labels they request and keep the following records for at least five years:

(1) Written documentation of the request from the equipment manufacturer.

(2) The number of duplicate labels you send and the date you sent them.

§ 1039.140 What is my engine's maximum engine power?

(a) An engine configuration's maximum engine power is the maximum brake power point on the nominal power curve for the engine configuration, as defined in this section. Round the power value to the nearest whole kilowatt.

(b) The nominal power curve of an engine configuration is the relationship between maximum available engine brake power and engine speed for an engine, using the mapping procedures of 40 CFR part 1065, based on the manufacturer's design and production specifications for the engine. This information may also be expressed by a torque curve that relates maximum available engine torque with engine speed.

(c) The nominal power curve must be within the range of the actual power curves of production engines considering normal production variability. If after production begins it is determined that your nominal power curve does not represent production engines, we may require you to amend your application for certification under § 1039.225.

(d) Throughout this part, references to a specific power value or a range of power values for an engine are based on maximum engine power. For example, the group of engines with maximum engine power above 560 kW may be referred to as engines above 560 kW.

Subpart C—Certifying Engine Families

§ 1039.201 What are the general requirements for obtaining a certificate of conformity?

(a) You must send us a separate application for a certificate of conformity for each engine family. A certificate of conformity is valid from the indicated effective date until December 31 of the model year for which it is issued.

(b) The application must contain all the information required by this part and must not include false or incomplete statements or information (see § 1039.255).

(c) We may ask you to include less information than we specify in this subpart, as long as you maintain all the information required by § 1039.250.

(d) You must use good engineering judgment for all decisions related to your application (see 40 CFR 1068.5).

(e) An authorized representative of your company must approve and sign the application.

(f) See § 1039.255 for provisions describing how we will process your application.

(g) We may require you to deliver your test engines to a facility we designate for our testing (see § 1039.235(c)).

§ 1039.205 What must I include in my application?

This section specifies the information that must be in your application, unless we ask you to include less information under § 1039.201(c). We may require you to provide additional information to evaluate your application.

(a) Describe the engine family's specifications and other basic parameters of the engine's design and emission controls. List the fuel type on which your engines are designed to operate (for example, ultra low-sulfur diesel fuel). List each distinguishable engine configuration in the engine family. For each engine configuration, list the maximum engine power and the range of values for maximum engine power resulting from production tolerances, as described in § 1039.140.

(b) Explain how the emission-control system operates. Describe in detail all system components for controlling exhaust emissions, including all auxiliary-emission control devices (AECDs) and all fuel-system components you will install on any production or test engine. Identify the part number of each component you describe. For this paragraph (b), treat as separate AECDs any devices that modulate or activate differently from each other. Include all the following:

(1) Give a general overview of the engine, the emission-control strategies, and all AECDs.

(2) Describe each AECD's general purpose and function.

(3) Identify the parameters that each AECD senses (including measuring, estimating, calculating, or empirically deriving the values). Include equipment-based parameters and state whether you simulate them during testing with the applicable procedures.

(4) Describe the purpose for sensing each parameter.

(5) Identify the location of each sensor the AECD uses.

(6) Identify the threshold values for the sensed parameters that activate the AECD.

(7) Describe the parameters that the AECD modulates (controls) in response to any sensed parameters, including the range of modulation for each parameter, the relationship between the sensed parameters and the controlled parameters and how the modulation achieves the AECD's stated purpose. Use graphs and tables, as necessary.

(8) Describe each AECD's specific calibration details. This may be in the form of data tables, graphical representations, or some other description.

(9) Describe the hierarchy among the AECDs when multiple AECDs sense or modulate the same parameter. Describe whether the strategies interact in a comparative or additive manner and identify which AECD takes precedence in responding, if applicable.

(10) Explain the extent to which the AECD is included in the applicable test procedures specified in subpart F of this part.

(11) Do the following additional things for AECDs designed to protect engines or equipment:

(i) Identify the engine and/or equipment design limits that make protection necessary and describe any damage that would occur without the AECD.

(ii) Describe how each sensed parameter relates to the protected components' design limits or those operating conditions that cause the need for protection.

(iii) Describe the relationship between the design limits/parameters being protected and the parameters sensed or calculated as surrogates for those design limits/parameters, if applicable.

(iv) Describe how the modulation by the AECD prevents engines and/or equipment from exceeding design limits.

(v) Explain why it is necessary to estimate any parameters instead of measuring them directly and describe how the AECD calculates the estimated value, if applicable.

(vi) Describe how you calibrate the AECD modulation to activate only during conditions related to the stated need to protect components and only as needed to sufficiently protect those components in a way that minimizes the emission impact.

(c) [Reserved]

(d) Describe the engines you selected for testing and the reasons for selecting them.

(e) Describe the test equipment and procedures that you used, including any special or alternate test procedures you used (see § 1039.501).

(f) Describe how you operated the emission-data engine before testing, including the duty cycle and the number of engine operating hours used to stabilize emission levels. Explain why you selected the method of service accumulation. Describe any scheduled maintenance you did.

(g) List the specifications of the test fuel to show that it falls within the required ranges we specify in 40 CFR part 1065.

(h) Identify the engine family's useful life.

(i) Include the maintenance instructions you will give to the ultimate purchaser of each new nonroad engine (see § 1039.125).

(j) Include the emission-related installation instructions you will provide if someone else installs your engines in a piece of nonroad equipment (see § 1039.130).

(k) Describe your emission control information label (see § 1039.135).

(l) Identify the emission standards or FELs to which you are certifying engines in the engine family. Identify the ambient operating regions that will apply for NTE testing under § 1039.101(e)(4).

(m) Identify the engine family's deterioration factors and describe how you developed them (see § 1039.245). Present any emission test data you used for this.

(n) State that you operated your emission-data engines as described in the application (including the test procedures, test parameters, and test fuels) to show you meet the requirements of this part.

(o) Present emission data for hydrocarbons (such as NMHC or THCE, as applicable), NO_X, PM, and C_O on an emission-data engine to show your engines meet the applicable duty-cycle emission standards we specify in § 1039.101. Show emission data figures before and after applying adjustment factors for regeneration and deterioration factors for each engine. Present emission data to show that you meet any applicable smoke standards we specify in § 1039.105. If we specify more than one grade of any fuel type (for example, high-sulfur and low-sulfur diesel fuel), you need to submit test data only for one grade, unless the regulations of this part specify otherwise for your engine. Note that § 1039.235 allows you to submit an application in certain cases without new emission data.

(p) State that all the engines in the engine family comply with the not-to-exceed emission standards we specify in subpart B of this part for all normal operation and use when tested as specified in § 1039.515. Describe any relevant testing, engineering analysis, or other information in sufficient detail to support your statement.

(q) For engines above 560 kW, include information showing how your emission controls will function during normal in-use transient operation. For example, this might include the following:

(1) Emission data from transient testing of engines using measurement systems designed for measuring in-use emissions.

(2) Comparison of the engine design for controlling transient emissions with that from engines for which you have emission data over the transient duty cycle for certification.

(3) Detailed descriptions of control algorithms and other design parameters for controlling transient emissions.

(r) Report all test results, including those from invalid tests or from any other tests, whether or not they were conducted according to the test procedures of subpart F of this part. If you measure CO_2, report those emission levels. We may ask you to send other information to confirm that your tests were valid under the requirements of this part and 40 CFR part 1065.

(s) Describe all adjustable operating parameters (see § 1039.115(e)), including production tolerances. Include the following in your description of each parameter:

(1) The nominal or recommended setting.

(2) The intended physically adjustable range.

(3) The limits or stops used to establish adjustable ranges.

(4) Information showing why the limits, stops, or other means of inhibiting adjustment are effective in preventing adjustment of parameters on in-use engines to settings outside your intended physically adjustable ranges.

(t) Provide the information to read, record, and interpret all the information broadcast by an engine's onboard computers and electronic control units.

State that, upon request, you will give us any hardware, software, or tools we would need to do this. If you broadcast a surrogate parameter for torque values, you must provide us what we need to convert these into torque units. You may reference any appropriate publicly released standards that define conventions for these messages and parameters. Format your information consistent with publicly released standards.

(u) Confirm that your emission-related installation instructions specify how to ensure that sampling of exhaust emissions will be possible after engines are installed in equipment and placed in service. If this cannot be done by simply adding a 20-centimeter extension to the exhaust pipe, show how to sample exhaust emissions in a way that prevents diluting the exhaust sample with ambient air.

(v) State whether your certification is limited for certain engines. If this is the case, describe how you will prevent use of these engines in applications for which they are not certified. This applies for engines such as the following:

(1) Constant-speed engines.

(2) Engines used for transportation refrigeration units that you certify under the provisions of § 1039.645.

(3) Hand-startable engines certified under the provisions of § 1039.101(c).

(4) Engines above 560 kW that are not certified to emission standards for generator-set engines.

(w) Unconditionally certify that all the engines in the engine family comply with the requirements of this part, other referenced parts of the CFR, and the Clean Air Act.

(x) Include estimates of U.S.-directed production volumes.

(y) Include the information required by other subparts of this part. For example, include the information required by § 1039.725 if you participate in the ABT program.

(z) Include other applicable information, such as information specified in this part or 40 CFR part 1068 related to requests for exemptions.

§ 1039.210 May I get preliminary approval before I complete my application?

If you send us information before you finish the application, we will review it and make any appropriate determinations, especially for questions related to engine family definitions, auxiliary emission-control devices, deterioration factors, testing for service accumulation, maintenance, and NTE deficiencies and carve-outs. Decisions made under this section are considered to be preliminary approval, subject to final review and approval. If you request preliminary approval related to the upcoming model year or the model year after that, we will make best-efforts to make the appropriate determinations as soon as practicable. We will generally not provide preliminary approval related to a future model year more than two years ahead of time.

§ 1039.220 How do I amend the maintenance instructions in my application?

You may amend your emission-related maintenance instructions after you submit your application for certification, as long as the amended instructions remain consistent with the provisions of § 1039.125. You must send the Designated Compliance Officer a request to amend your application for certification for an engine family if you want to change the emission-related maintenance instructions in a way that could affect emissions. In your request, describe the proposed changes to the maintenance instructions. We will disapprove your request if we determine that the amended instructions are inconsistent with maintenance you performed on emission-data engines.

(a) If you are decreasing the specified maintenance, you may distribute the new maintenance instructions to your customers 30 days after we receive your request, unless we disapprove your request. We may approve a shorter time or waive this requirement.

(b) If your requested change would not decrease the specified maintenance, you may distribute the new maintenance instructions anytime after you send your request. For example, this paragraph (b) would cover adding instructions to increase the frequency of a maintenance step for engines in severe-duty applications.

(c) You need not request approval if you are making only minor corrections (such as correcting typographical mistakes), clarifying your maintenance instructions, or changing instructions for maintenance unrelated to emission control.

§ 1039.225 How do I amend my application for certification to include new or modified engines?

Before we issue you a certificate of conformity, you may amend your application to include new or modified engine configurations, subject to the provisions of this section. After we have issued your certificate of conformity, you may send us an amended application requesting that we include new or modified engine configurations within the scope of the certificate, subject to the provisions of this section. You must amend your application if any changes occur with respect to any information included in your application.

(a) You must amend your application before you take either of the following actions:

(1) Add an engine (that is, an additional engine configuration) to an engine family. In this case, the engine added must be consistent with other engines in the engine family with respect to the criteria listed in § 1039.230.

(2) Change an engine already included in an engine family in a way that may affect emissions, or change any of the components you described in your application for certification. This includes production and design changes that may affect emissions any time during the engine's lifetime.

(b) To amend your application for certification, send the Designated Compliance Officer the following information:

(1) Describe in detail the addition or change in the engine model or configuration you intend to make.

(2) Include engineering evaluations or data showing that the amended engine family complies with all applicable requirements. You may do this by showing that the original emission-data engine is still appropriate with respect to showing compliance of the amended family with all applicable requirements.

(3) If the original emission-data engine for the engine family is not appropriate to show compliance for the new or modified nonroad engine, include new test data showing that the new or modified nonroad engine meets the requirements of this part.

(c) We may ask for more test data or engineering evaluations. You must give us these within 30 days after we request them.

(d) For engine families already covered by a certificate of conformity, we will determine whether the existing certificate of conformity covers your new or modified nonroad engine. You may ask for a hearing if we deny your request (see § 1039.820).

(e) For engine families already covered by a certificate of conformity, you may start producing the new or modified nonroad engine anytime after you send us your amended application, before we make a decision under paragraph (d) of this section. However, if we determine that the affected engines do not meet applicable requirements, we will notify you to cease production of the engines and may require you to recall the engines at no expense to the owner. Choosing to produce engines under this paragraph (e) is deemed to be consent to recall all engines that we determine do not meet applicable emission standards or other requirements and to remedy the nonconformity at no expense to the owner. If you do not provide information required under paragraph (c) of this section within 30 days, you must stop producing the new or modified nonroad engines.

§ 1039.230 How do I select engine families?

(a) Divide your product line into families of engines that are expected to have similar emission characteristics throughout the useful life. Your engine family is limited to a single model year.

(b) Group engines in the same engine family if they are the same in all the following aspects:

(1) The combustion cycle and fuel.

(2) The cooling system (water-cooled vs. air-cooled).

(3) Method of air aspiration.

(4) Method of exhaust aftertreatment (for example, catalytic converter or particulate trap).

(5) Combustion chamber design.

(6) Bore and stroke.

(7) Number of cylinders (for engines with aftertreatment devices only).

(8) Cylinder arrangement (for engines with aftertreatment devices only).

(9) Method of control for engine operation other than governing (*i.e.*, mechanical or electronic).

(10) Power category.

(11) Numerical level of the emission standards that apply to the engine.

(c) You may subdivide a group of engines that is identical under paragraph (b) of this section into different engine families if you show the expected emission characteristics are different during the useful life.

(d) You may group engines that are not identical with respect to the things listed in paragraph (b) of this section in the same engine family if you show that their emission characteristics during the useful life will be similar.

(e) If you combine engines from different power categories into a single engine family under paragraph (d) of this section, you must certify the engine family to the more stringent set of standards from the two power categories in that model year.

§ 1039.235 What emission testing must I perform for my application for a certificate of conformity?

This section describes the emission testing you must perform to show compliance with the emission standards in § 1039.101(a) and (b) or § 1039.102(a) and (b). See § 1039.205(p) regarding emission testing related to the NTE standards. See § 1039.240, § 1039.245, and 40 CFR part 1065, subpart E, regarding service accumulation before emission testing.

(a) Test your emission-data engines using the procedures and equipment specified in subpart F of this part.

(b) Select an emission-data engine from each engine family for testing. Select the engine configuration with the highest volume of fuel injected per cylinder per combustion cycle at the point of maximum torque—unless good engineering judgment indicates that a different engine configuration is more likely to exceed (or have emissions nearer to) an applicable emission standard or FEL. If two or more engines have the same fueling rate at maximum torque, select the one with the highest fueling rate at rated speed. In making this selection, consider all factors expected to affect emission-control performance and compliance with the standards, including emission levels of all exhaust constituents, especially NO_X and PM.

(c) We may measure emissions from any of your test engines or other engines from the engine family, as follows:

(1) We may decide to do the testing at your plant or any other facility. If we do this, you must deliver the test engine to a test facility we designate. The test engine you provide must include appropriate manifolds, aftertreatment devices, electronic control units, and other emission-related components not normally attached directly to the engine block. If we do the testing at your plant, you must schedule it as soon as possible and make available the instruments, personnel, and equipment we need.

(2) If we measure emissions on one of your test engines, the results of that testing become the official emission results for the engine. Unless we later invalidate these data, we may decide not to consider your data in determining if your engine family meets applicable requirements.

(3) Before we test one of your engines, we may set its adjustable parameters to any point within the physically adjustable ranges (see § 1039.115(e)).

(4) Before we test one of your engines, we may calibrate it within normal production tolerances for anything we do not consider an adjustable parameter.

(d) You may ask to use emission data from a previous model year instead of doing new tests, but only if all the following are true:

(1) The engine family from the previous model year differs from the current engine family only with respect to model year.

(2) The emission-data engine from the previous model year remains the appropriate emission-data engine under paragraph (b) of this section.

(3) The data show that the emission-data engine would meet all the requirements that apply to the engine family covered by the application for certification.

(e) We may require you to test a second engine of the same or different configuration in addition to the engine tested under paragraph (b) of this section.

(f) If you use an alternate test procedure under 40 CFR 1065.10 and later testing shows that such testing does not produce results that are equivalent to the procedures specified in subpart F of this part, we may reject data you generated using the alternate procedure.

§ 1039.240 How do I demonstrate that my engine family complies with exhaust emission standards?

(a) For purposes of certification, your engine family is considered in compliance with the applicable numerical emission standards in § 1039.101(a) and (b) or in § 1039.102(a) and (b) if all emission-data engines representing that family have test results showing deteriorated emission levels at or below these standards. (**Note:** if you participate in the ABT program in subpart H of this part, your FELs are considered to be the applicable emission standards with which you must comply.)

(b) Your engine family is deemed not to comply if any emission-data engine representing that family has test results showing a deteriorated emission level above an applicable FEL or emission standard from § 1039.101 for any pollutant.

(c) To compare emission levels from the emission-data engine with the applicable emission standards, apply deterioration factors to the measured emission levels for each pollutant. Section 1039.245 specifies how to test your engine to develop deterioration factors that represent the deterioration expected in emissions over your engines' full useful life. Your deterioration factors must take into account any available data from in-use testing with similar engines. Small-volume engine manufacturers may use assigned deterioration factors that we establish. Apply deterioration factors as follows:

(1) *Additive deterioration factor for exhaust emissions.* Except as specified in paragraph (c)(2) of this section, use an additive deterioration factor for exhaust emissions. An additive deterioration factor for a pollutant is the difference between exhaust emissions at

the end of the useful life and exhaust emissions at the low-hour test point. In these cases, adjust the official emission results for each tested engine at the selected test point by adding the factor to the measured emissions. If the factor is less than zero, use zero. Additive deterioration factors must be specified to one more decimal place than the applicable standard.

(2) *Multiplicative deterioration factor for exhaust emissions.* Use a multiplicative deterioration factor if good engineering judgment calls for the deterioration factor for a pollutant to be the ratio of exhaust emissions at the end of the useful life to exhaust emissions at the low-hour test point. For example, if you use aftertreatment technology that controls emissions of a pollutant proportionally to engine-out emissions, it is often appropriate to use a multiplicative deterioration factor. Adjust the official emission results for each tested engine at the selected test point by multiplying the measured emissions by the deterioration factor. If the factor is less than one, use one. A multiplicative deterioration factor may not be appropriate in cases where testing variability is significantly greater than engine-to-engine variability. Multiplicative deterioration factors must be specified to one more significant figure than the applicable standard.

(3) *Deterioration factor for smoke.* Deterioration factors for smoke are always additive, as described in paragraph (c)(1) of this section.

(4) *Deterioration factor for crankcase emissions.* If your engine vents crankcase emissions to the exhaust or to the atmosphere, you must account for crankcase emission deterioration, using good engineering judgment. You may use separate deterioration factors for crankcase emissions of each pollutant (either multiplicative or additive) or include the effects in combined deterioration factors that include exhaust and crankcase emissions together for each pollutant.

(d) Collect emission data using measurements to one more decimal place than the applicable standard. Apply the deterioration factor to the official emission result, as described in paragraph (c) of this section, then round the adjusted figure to the same number of decimal places as the emission standard. Compare the rounded emission levels to the emission standard for each emission-data engine. In the case of NO_X+NMHC standards, apply the deterioration factor to each pollutant and then add the results before rounding.

(e) For engines subject to NMHC standards, you may base compliance on total hydrocarbon (THC) emissions. Indicate in your application for certification if you are using this option. If you do, measure THC emissions and calculate NMHC emissions as 98 percent of THC emissions, as shown in the following equation:

$$NMHC = (0.98) \times (THC).$$

§ 1039.245 How do I determine deterioration factors from exhaust durability testing?

Establish deterioration factors to determine whether your engines will meet emission standards for each pollutant throughout the useful life, as described in §§ 1039.101 and 1039.240. This section describes how to determine deterioration factors, either with an engineering analysis, with pre-existing test data, or with new emission measurements. If you are required to perform durability testing, see § 1039.125 for limitations on the maintenance that you may perform on your emission-data engine.

(a) You may ask us to approve deterioration factors for an engine family with established technology based on engineering analysis instead of testing. Engines certified to a NO_X+NMHC standard or FEL greater than the Tier 3 NO_X+NMHC standard described in 40 CFR 89.112 are considered to rely on established technology for gaseous emission control, except that this does not include any engines that use exhaust-gas recirculation or aftertreatment. In most cases, technologies used to meet the Tier 1 and Tier 2 emission standards would be considered to be established technology.

(b) You may ask us to approve deterioration factors for an engine family based on emission measurements from similar highway or nonroad engines if you have already given us these data for certifying the other engines in the same or earlier model years. Use good engineering judgment to decide whether the two engines are similar. We will approve your request if you show us that the emission measurements from other engines reasonably represent in-use deterioration for the engine family for which you have not yet determined deterioration factors.

(c) If you are unable to determine deterioration factors for an engine family under paragraph (a) or (b) of this section, select engines, subsystems, or components for testing. Determine deterioration factors based on service accumulation and related testing to represent the deterioration expected from in-use engines over the full useful life. You must measure emissions from the emission-data engine at least three times with evenly spaced intervals of service accumulation. You may use extrapolation to determine deterioration factors once you have established a trend of changing emissions with age for each pollutant. You may use an engine installed in nonroad equipment to accumulate service hours instead of running the engine only in the laboratory. You may perform maintenance on emission-data engines as described in § 1039.125 and 40 CFR part 1065, subpart E. Use good engineering judgment for all aspects of the effort to establish deterioration factors under this paragraph (c).

(d) Include the following information in your application for certification:

(1) If you use test data from a different engine family, explain why this is appropriate and include all the emission measurements on which you base the deterioration factor.

(2) If you determine your deterioration factors based on engineering analysis, explain why this is appropriate and include a statement that all data, analyses, evaluations, and other information you used are available for our review upon request.

(3) If you do testing to determine deterioration factors, describe the form and extent of service accumulation, including a rationale for selecting the service-accumulation period and the method you use to accumulate hours.

§ 1039.250 What records must I keep and what reports must I send to EPA?

(a) Within 30 days after the end of the model year, send the Designated Compliance Officer a report describing the following information about engines you produced during the model year:

(1) Report the total number of engines you produced in each engine family by maximum engine power, total displacement, and the type of fuel system.

(2) If you produced exempted engines under the provisions of § 1039.625, report the number of exempted engines you produced for each engine model and identify the buyer or shipping destination for each exempted engine.

(b) Organize and maintain the following records:

(1) A copy of all applications and any summary information you send us.

(2) Any of the information we specify in § 1039.205 that you were not required to include in your application.

(3) A detailed history of each emission-data engine. For each engine, describe all of the following:

(i) The emission-data engine's construction, including its origin and buildup, steps you took to ensure that it represents production engines, any components you built specially for it, and all the components you include in your application for certification.

(ii) How you accumulated engine operating hours (service accumulation), including the dates and the number of hours accumulated.

(iii) All maintenance, including modifications, parts changes, and other service, and the dates and reasons for the maintenance.

(iv) All your emission tests, including documentation on routine and standard tests, as specified in part 40 CFR part 1065, and the date and purpose of each test.

(v) All tests to diagnose engine or emission-control performance, giving the date and time of each and the reasons for the test.

(vi) Any other significant events.

(4) Production figures for each engine family divided by assembly plant.

(5) Keep a list of engine identification numbers for all the engines you produce under each certificate of conformity.

(c) Keep data from routine emission tests (such as test cell temperatures and relative humidity readings) for one year after we issue the associated certificate of conformity. Keep all other information specified in paragraph (a) of this section for eight years after we issue your certificate.

(d) Store these records in any format and on any media, as long as you can promptly send us organized, written records in English if we ask for them. You must keep these records readily available. We may review them at any time.

(e) Send us copies of any engine maintenance instructions or explanations if we ask for them.

§ 1039.255 What decisions may EPA make regarding my certificate of conformity?

(a) If we determine your application is complete and shows that the engine family meets all the requirements of this part and the Act, we will issue a certificate of conformity for your engine family for that model year. We may make the approval subject to additional conditions.

(b) We may deny your application for certification if we determine that your engine family fails to comply with emission standards or other requirements of this part or the Act. Our decision may be based on a review of all information available to us. If we deny your application, we will explain why in writing.

(c) In addition, we may deny your application or suspend or revoke your certificate if you do any of the following:

(1) Refuse to comply with any testing or reporting requirements.

(2) Submit false or incomplete information (paragraph (e) of this section applies if this is fraudulent).

(3) Render inaccurate any test data.

(4) Deny us from completing authorized activities despite our presenting a warrant or court order (see 40 CFR 1068.20). This includes a failure to provide reasonable assistance.

(5) Produce engines for importation into the United States at a location where local law prohibits us from carrying out authorized activities.

(6) Fail to supply requested information or amend your application to include all engines being produced.

(7) Take any action that otherwise circumvents the intent of the Act or this part.

(d) We may void your certificate if you do not keep the records we require or do not give us information when we ask for it.

(e) We may void your certificate if we find that you intentionally submitted false or incomplete information.

(f) If we deny your application or suspend, revoke, or void your certificate, you may ask for a hearing (see § 1039.820).

§ 1039.260 What provisions apply to engines that are conditionally exempted from certification?

As specified elsewhere in this part or in 40 CFR part 1068, you may in some cases introduce engines into commerce that are exempt from the requirement to certify engines to the otherwise applicable standards. If we specify alternate standards as a condition of the exemption, all the following provisions apply:

(a) Your engines must meet the alternate standards we specify in the exemption section, and all other requirements applicable to engines that are subject to such standards.

(b) You need not apply for and receive a certificate for the exempt engines. However, you must comply with all the requirements and obligations that would apply to the engines if you had received a certificate of conformity for them, unless we specifically waive certain requirements.

(c) You must have emission data from testing engines using the appropriate procedures that demonstrate compliance with the alternate standards, unless the engines are identical in all material respects to engines that you have previously certified to standards that are the same as, or more stringent than, the alternate standards.

(d) Unless we specify otherwise elsewhere in this part or in 40 CFR part 1068, you must meet the labeling requirements in § 1039.135, with the following exceptions:

(1) Instead of the engine family designation specified in § 1039.135(c)(3), use a modified designation to identify the group of engines that would otherwise be included in the same engine family.

(2) Instead of the compliance statement in § 1039.135(c)(12), add the following statement: "THIS ENGINE MEETS U.S. EPA EMISSION STANDARDS UNDER 40 CFR 1039.260.".

(e) You may not generate ABT credits with engines meeting requirements under the provisions of this section.

(f) Keep records to show that you meet the alternate standards, as follows:

(1) If your exempted engines are identical to previously certified engines, keep your most recent application for certification for the certified engine family.

(2) If you previously certified a similar engine family, but have modified the exempted engine in a way that changes it from its previously certified configuration, keep your most recent application for certification for the certified engine family, a description of the relevant changes, and any test data or engineering evaluations that support your conclusions.

(3) If you have not previously certified a similar engine family, keep all the records we specify for the application for certification and the additional records we specify in § 1039.250(b)(3).

(g) We may require you to send us an annual report of the engines you produce under this section.

Subpart D—[Reserved]

Subpart E—In-Use Testing

§ 1039.401 General provisions.

We may perform in-use testing of any engine subject to the standards of this part. However, we will limit recall testing to the first 75 percent of each engine's useful life as specified in § 1039.101(g).

Subpart F—Test Procedures

§ 1039.501 How do I run a valid emission test?

(a) Use the equipment and procedures for compression-ignition engines in 40 CFR part 1065 to determine whether engines meet the duty-cycle emission standards in § 1039.101(a) and (b). Measure the emissions of all the pollutants we regulate in § 1039.101 as specified in 40 CFR part 1065. Note that we do not allow partial-flow sampling for measuring PM emissions on a laboratory dynamometer for transient testing. Use the applicable duty cycles specified in §§ 1039.505 and 1039.510.

(b) Section 1039.515 describes the supplemental procedures for evaluating whether engines meet the not-to-exceed emission standards in § 1039.101(e).

(c) Measure smoke using the procedures in 40 CFR part 86, subpart I, for evaluating whether engines meet the smoke standards in § 1039.105, except that you may test two-cylinder engines with an exhaust muffler like those installed on in-use engines.

(d) Use the fuels specified in § 1039.104(e) and 40 CFR part 1065 to perform valid tests.

(1) For service accumulation, use the test fuel or any commercially available fuel that is representative of the fuel that in-use engines will use.

(2) For diesel-fueled engines, use the appropriate diesel fuel specified in 40 CFR part 1065 for emission testing. Unless we specify otherwise, the appropriate diesel test fuel is the ultra low-sulfur diesel fuel. If we allow you to use a test fuel with higher sulfur levels, identify the test fuel in your application for certification and ensure that the emission control information label is consistent with your selection of the test fuel (see § 1039.135(c)(9)). For example, do not test with ultra low-sulfur diesel fuel if you intend to label your engines to allow use of diesel fuel with sulfur concentrations up to 500 ppm.

(e) You may use special or alternate procedures to the extent we allow them under 40 CFR 1065.10.

(f) This subpart is addressed to you as a manufacturer, but it applies equally to anyone who does testing for you, and to us when we perform testing to determine if your engines meet emission standards.

§ 1039.505 How do I test engines using steady-state duty cycles, including ramped-modal testing?

This section describes how to test engines under steady-state conditions. In some cases, we allow you to choose the appropriate steady-state duty cycle for an engine. In these cases, you must use the duty cycle you select in your application for certification for all testing you perform for that engine family. If we test your engines to confirm that they meet emission standards, we will use the duty cycles you select for your own testing. We may also perform other testing as allowed by the Clean Air Act.

(a) You may perform steady-state testing with either discrete-mode or ramped-modal cycles, as follows:

(1) For discrete-mode testing, sample emissions separately for each mode, then calculate an average emission level for the whole cycle using the weighting factors specified for each mode. Calculate cycle statistics for the sequence of modes and compare with the specified values in 40 CFR part 1065 to confirm that the test is valid. Operate the engine and sampling system as follows:

(i) *Engines with NO_X aftertreatment.* For engines that depend on aftertreatment to meet the NO_X emission standard, operate the engine for 5–6 minutes, then sample emissions for 1–3 minutes in each mode. You may extend the sampling time to improve measurement accuracy of PM emissions, using good engineering judgment. If you have a longer sampling time for PM emissions, calculate and validate cycle statistics separately for the gaseous and PM sampling periods.

(ii) *Engines without NO_X aftertreatment.* For other engines, operate the engine for at least 5 minutes, then sample emissions for at least 1 minute in each mode. Calculate cycle statistics for the sequence of modes and compare with the specified values in 40 CFR part 1065 to confirm that the test is valid.

(2) For ramped-modal testing, start sampling at the beginning of the first mode and continue sampling until the end of the last mode. Calculate emissions and cycle statistics the same as for transient testing.

(b) Measure emissions by testing the engine on a dynamometer with one of the following duty cycles to determine whether it meets the steady-state emission standards in § 1039.101(b):

(1) Use the 5-mode duty cycle or the corresponding ramped-modal cycle described in Appendix II of this part for constant-speed engines. Note that these cycles do not apply to all engines used in constant-speed applications, as described in § 1039.801.

(2) Use the 6-mode duty cycle or the corresponding ramped-modal cycle described in Appendix III of this part for variable-speed engines below 19 kW. You may instead use the 8-mode duty cycle or the corresponding ramped-modal cycle described in Appendix IV of this part if some engines from your engine family will be used in applications that do not involve governing to maintain engine operation around rated speed.

(3) Use the 8-mode duty cycle or the corresponding ramped-modal cycle described in Appendix IV of this part for variable-speed engines at or above 19 kW.

(c) During idle mode, operate the engine with the following parameters:

(1) Hold the speed within your specifications.

(2) Set the engine to operate at its minimum fueling rate.

(3) Keep engine torque under 5 percent of maximum test torque.

(d) For full-load operating modes, operate the engine at its maximum fueling rate. However, for constant-speed engines whose design prevents full-load operation for extended periods, you may ask for approval under 40 CFR 1065.10(c) to replace full-load operation with the maximum load for which the engine is designed to operate for extended periods.

(e) See 40 CFR part 1065 for detailed specifications of tolerances and calculations.

(f) For those cases where transient testing is not necessary, perform the steady-state test according to this section after an appropriate warm-up period, consistent with 40 CFR part 1065, subpart F.

§ 1039.510 Which duty cycles do I use for transient testing?

(a) Measure emissions by testing the engine on a dynamometer with one of the following transient duty cycles to determine whether it meets the transient emission standards in § 1039.101(a):

(1) For variable-speed engines, use the transient duty cycle described in Appendix VI of this part.

(2) [Reserved]

(b) The transient test sequence consists of an initial run through the transient duty cycle from a cold start, 20 minutes with no engine operation, then a final run through the same transient duty cycle. Start sampling emissions immediately after you start the engine. Calculate the official transient emission result from the following equation:

Official transient emission result = 0.05 × cold-start emission rate + 0.95 × hot-start emission rate.

(c) Cool the engine down between tests as described in 40 CFR 86.1335–90.

(d) For validating cycle statistics, you may delete from your regression analysis speed, torque, and power points for the first 23 seconds and the last 25 seconds of the transient duty cycle.

§ 1039.515 What are the test procedures related to not-to-exceed standards?

(a) *General provisions.* The provisions in 40 CFR 86.1370–2007 apply for determining whether an engine meets the not-to-exceed emission standards in § 1039.101(e). Interpret references to vehicles and vehicle operation to mean equipment and equipment operation.

(b) *Special PM zone.* For engines certified to a PM standard or FEL above 0.07 g/kW-hr, a modified NTE control area applies for PM emissions only. The speeds and loads to be excluded are determined based on speeds B and C, determined according to the provisions of 40 CFR 86.1360–2007(c). One of the following provisions applies:

(1) If the C speed is below 2400 rpm, exclude the speed and load points to the right of or below the line formed by connecting the following two points on a plot of speed-vs.-power:

(i) 30% of maximum power at the B speed; however, use the power value corresponding to the engine operation at 30% of maximum torque at the B speed if this is greater than 30% of maximum power at the B speed.

(ii) 70% of maximum power at 100% speed.

(2) If the C speed is at or above 2400 rpm, exclude the speed and load points to the right of the line formed by connecting the two points in paragraphs (b)(2)(i) and (ii) of this section (the 30% and 50% torque/power points) and below the line formed by connecting the two points in paragraphs (b)(2)(ii) and (iii) of this section (the 50% and 70% torque/power points). The 30%, 50%, and 70% torque/power points are defined as follows:

(i) 30% of maximum power at the B speed; however, use the power value corresponding to the engine operation at 30% of maximum torque at the B speed if this is greater than 30% of maximum power at the B speed.

(ii) 50% of maximum power at 2400 rpm.

(iii) 70% of maximum power at 100% speed.

§ 1039.520 What testing must I perform to establish deterioration factors?

Sections 1039.240 and 1039.245 describe the method for testing that must be performed to establish deterioration factors for an engine family.

§ 1039.525 How do I adjust emission levels to account for infrequently regenerating aftertreatment devices?

This section describes how to adjust emission results from engines using aftertreatment technology with infrequent regeneration events. For this section, "regeneration" means an intended event during which emission levels change while the system restores aftertreatment performance. For example, exhaust gas temperatures may increase temporarily to remove sulfur from adsorbers or to oxidize accumulated particulate matter in a trap. For this section, "infrequent" refers to regeneration events that are expected to occur on average less than once over the applicable transient duty cycle or ramped-modal cycle, or on average less than once per typical mode in a discrete-mode test.

(a) *Developing adjustment factors.* Develop an upward adjustment factor and a downward adjustment factor for each pollutant based on measured emission data and observed regeneration frequency. Adjustment factors should generally apply to an entire engine family, but you may develop separate adjustment factors for different engine configurations within an engine family. If you use adjustment factors for certification, you must identify the frequency factor, F, from paragraph (b) of this section in your application for certification and use the adjustment factors in all testing for that engine family. You may use carryover or carry-across data to establish adjustment factors for an engine family, as described in § 1039.235(d), consistent with good engineering judgment. All adjustment factors for regeneration are additive. Determine adjustment factors separately for different test segments. For example, determine separate adjustment factors for hot-start and cold-start test segments and for different modes of a discrete-mode steady-state test. You may use either of the following different approaches for engines that use aftertreatment with infrequent regeneration events:

(1) You may disregard this section if regeneration does not significantly affect emission levels for an engine family (or configuration) or if it is not practical to identify when regeneration occurs. If you do not use adjustment factors under this section, your engines must meet emission standards for all testing, without regard to regeneration.

(2) If your engines use aftertreatment technology with extremely infrequent regeneration and you are unable to apply the provisions of this section, you may ask us to approve an alternate methodology to account for regeneration events.

(b) *Calculating average adjustment factors.* Calculate the average adjustment factor (EF_A) based on the following equation:

$$EF_A = (F)(EF_H) + (1\text{-}F)(EF_L)$$

Where:

F = the frequency of the regeneration event in terms of the fraction of tests during which the regeneration occurs.

EF_H = measured emissions from a test segment in which the regeneration occurs.

EF_L = measured emissions from a test segment in which the regeneration does not occur.

(c) *Applying adjustment factors.* Apply adjustment factors based on whether regeneration occurs during the test run. You must be able to identify regeneration in a way that is readily apparent during all testing.

(1) If regeneration does not occur during a test segment, add an upward adjustment factor to the measured emission rate. Determine the upward adjustment factor (UAF) using the following equation:

$$UAF = EF_A - EF_L$$

(2) If regeneration occurs or starts to occur during a test segment, subtract a downward adjustment factor from the measured emission rate. Determine the downward adjustment factor (DAF) using the following equation:

$$DAF = EF_H - EF_A$$

(d) *Sample calculation.* If EF_L is 0.10 g/kW-hr, EF_H is 0.50 g/kW-hr, and F is 0.1 (the regeneration occurs once for each ten tests), then:

$$EF_A = (0.1)(0.5 \text{ g/kW-hr}) + (1.0 - 0.1)(0.1 \text{ g/kW-hr}) = 0.14 \text{ g/kW-hr}.$$

$$UAF = 0.14 \text{ g/kW-hr} - 0.10 \text{ g/kW-hr} = 0.04 \text{ g/kW-hr}.$$

$$DAF = 0.50 \text{ g/kW-hr} - 0.14 \text{ g/kW-hr} = 0.36 \text{ g/kW-hr}.$$

Subpart G—Special Compliance Provisions

§ 1039.601 What compliance provisions apply to these engines?

Engine and equipment manufacturers, as well as owners, operators, and rebuilders of engines subject to the requirements of this part, and all other persons, must observe the provisions of this part, the requirements and prohibitions in 40 CFR part 1068, and the provisions of the Act.

§ 1039.605 What provisions apply to engines already certified under the motor-vehicle program?

(a) *General provisions.* If you are an engine manufacturer, this section allows you to introduce new nonroad engines into commerce if they are already certified to the requirements that apply to compression-ignition engines under 40 CFR parts 85 and 86. If you comply with all the provisions of this section, we consider the certificate issued under 40 CFR part 86 for each engine to also be a valid certificate of conformity under this part 1039 for its model year, without a separate application for certification under the requirements of this part 1039. See § 1039.610 for similar provisions that apply to engines certified to chassis-based standards for motor vehicles.

(b) *Equipment-manufacturer provisions.* If you are not an engine manufacturer, you may produce nonroad equipment using motor-vehicle engines under this section as long as the engine has been properly labeled as specified in paragraph (d)(5) of this section and you do not make any of the changes described in paragraph (d)(2) of this section. You must also add the fuel-inlet label we specify in § 1039.135(e). If you modify the motor-vehicle engine in any of the ways described in paragraph (d)(2) of this section, we will consider you a manufacturer of a new nonroad engine. Such engine modifications prevent you from using the provisions of this section.

(c) *Liability.* Engines for which you meet the requirements of this section are exempt from all the requirements and prohibitions of this part, except for those specified in this section. Engines exempted under this section must meet all the applicable requirements from 40 CFR parts 85 and 86. This paragraph (c) applies to engine manufacturers, equipment manufacturers who use these engines, and all other persons as if these engines were used in a motor vehicle. The prohibited acts of § 1068.101(a)(1) apply to these new engines and equipment; however, we consider the certificate issued under 40 CFR part 86 for each engine to also be a valid certificate of conformity under this part 1039 for its model year. If we make a determination that these engines do not conform to the regulations during their useful life, we may require you to recall them under 40 CFR part 85 or 40 CFR 1068.505.

(d) *Specific requirements.* If you are an engine manufacturer and meet all the following criteria and requirements regarding your new nonroad engine, the engine is eligible for an exemption under this section:

(1) Your engine must be covered by a valid certificate of conformity issued under 40 CFR part 86.

(2) You must not make any changes to the certified engine that could reasonably be expected to increase its exhaust emissions for any pollutant, or its evaporative emissions if it is subject to evaporative-emission standards. For example, if you make any of the following changes to one of these engines, you do not qualify for this exemption:

(i) Change any fuel system parameters from the certified configuration.

(ii) Change, remove, or fail to properly install any other component, element of design, or calibration specified in the engine manufacturer's application for certification. This includes aftertreatment devices and all related components.

(iii) Modify or design the engine cooling system so that temperatures or heat rejection rates are outside the original engine manufacturer's specified ranges.

(3) You must show that fewer than 50 percent of the engine model's total sales for the model year, from all companies, are used in nonroad applications, as follows:

(i) If you are the original manufacturer of the engine, base this showing on your sales information.

(ii) In all other cases, you must get the original manufacturer of the engine to confirm this based on its sales information.

(4) You must ensure that the engine has the label we require under 40 CFR part 86.

(5) You must add a permanent supplemental label to the engine in a position where it will remain clearly visible after installation in the equipment. In the supplemental label, do the following:

(i) Include the heading: "NONROAD ENGINE EMISSION CONTROL INFORMATION".

(ii) Include your full corporate name and trademark. You may instead include the full corporate name and trademark of another company you choose to designate.

(iii) State: "THIS ENGINE WAS ADAPTED FOR NONROAD USE WITHOUT AFFECTING ITS EMISSION CONTROLS. THE EMISSION-CONTROL SYSTEM DEPENDS ON THE USE OF FUEL MEETING SPECIFICATIONS THAT APPLY FOR MOTOR-VEHICLE APPLICATIONS. OPERATING THE ENGINE ON OTHER FUELS MAY BE A VIOLATION OF FEDERAL LAW.".

(iv) State the date you finished modifying the engine (month and year), if applicable.

(6) The original and supplemental labels must be readily visible after the engine is installed in the equipment or, if the equipment obscures the engine's emission control information label, the equipment manufacturer must attach duplicate labels, as described in 40 CFR 1068.105.

(7) You must make sure that nonroad equipment produced under this section will have the fueling label we specify in § 1039.135(c)(9)(i).

(8) Send the Designated Compliance Officer a signed letter by the end of each calendar year (or less often if we tell you) with all the following information:

(i) Identify your full corporate name, address, and telephone number.

(ii) List the engine models you expect to produce under this exemption in the coming year.

(iii) State: "We produce each listed engine model for nonroad application without making any changes that could increase its certified emission levels, as described in 40 CFR 1039.605.".

(e) *Failure to comply.* If your engines do not meet the criteria listed in paragraph (d) of this section, they will be subject to the standards, requirements, and prohibitions of this part 1039 and the certificate issued under 40 CFR part 86 will not be deemed to also be a certificate issued under this part 1039. Introducing these engines into commerce without a valid exemption or certificate of conformity under this part violates the prohibitions in 40 CFR 1068.101(a)(1).

(f) *Data submission.* We may require you to send us emission test data on any applicable nonroad duty cycles.

§ 1039.610 What provisions apply to vehicles already certified under the motor-vehicle program?

(a) *General provisions.* If you are a motor-vehicle manufacturer, this section allows you to introduce new nonroad engines or equipment into commerce if the vehicle is already certified to the requirements that apply under 40 CFR parts 85 and 86. If you comply with all of the provisions of this section, we consider the certificate issued under 40 CFR part 86 for each motor vehicle to also be a valid certificate of conformity for the engine under this part 1039 for its model year, without a separate application for certification under the requirements of this part 1039. See § 1039.605 for similar provisions that apply to motor-vehicle engines produced for nonroad equipment.

(b) *Equipment-manufacturer provisions.* If you are not an engine manufacturer, you may produce nonroad equipment from motor vehicles under this section as long as the equipment has the labels specified in paragraph (d)(5) of this section and you do not make any of the changes described in paragraph (d)(2) of this section. You must also add the fuel-inlet label we specify in § 1039.135(e). If you modify the motor vehicle or its engine in any of the ways described in paragraph (d)(2) of this section, we will consider you a manufacturer of a new nonroad engine. Such modifications prevent you from using the provisions of this section.

(c) *Liability.* Engines, vehicles, and equipment for which you meet the requirements of this section are exempt from all the requirements and prohibitions of this part, except for those specified in this section. Engines exempted under this section must meet all the applicable requirements from 40

CFR parts 85 and 86. This applies to engine manufacturers, equipment manufacturers, and all other persons as if the nonroad equipment were motor vehicles. The prohibited acts of § 1068.101(a)(1) apply to these new pieces of equipment; however, we consider the certificate issued under 40 CFR part 86 for each motor vehicle to also be a valid certificate of conformity for the engine under this part 1039 for its model year. If we make a determination that these engines, vehicles, or equipment do not conform to the regulations during their useful life, we may require you to recall them under 40 CFR part 86 or 40 CFR 1068.505.

(d) *Specific requirements.* If you are a motor-vehicle manufacturer and meet all the following criteria and requirements regarding your new nonroad equipment and its engine, the engine is eligible for an exemption under this section:

(1) Your equipment must be covered by a valid certificate of conformity as a motor vehicle issued under 40 CFR part 86.

(2) You must not make any changes to the certified vehicle that we could reasonably expect to increase its exhaust emissions for any pollutant, or its evaporative emissions if it is subject to evaporative-emission standards. For example, if you make any of the following changes, you do not qualify for this exemption:

(i) Change any fuel system parameters from the certified configuration.

(ii) Change, remove, or fail to properly install any other component, element of design, or calibration specified in the vehicle manufacturer's application for certification. This includes aftertreatment devices and all related components.

(iii) Modify or design the engine cooling system so that temperatures or heat rejection rates are outside the original vehicle manufacturer's specified ranges.

(iv) Add more than 500 pounds to the curb weight of the originally certified motor vehicle.

(3) You must show that fewer than 50 percent of the total sales as a motor vehicle or a piece of nonroad equipment, from all companies, are used in nonroad applications, as follows:

(i) If you are the original manufacturer of the vehicle, base this showing on your sales information.

(ii) In all other cases, you must get the original manufacturer of the vehicle to confirm this based on their sales information.

(4) The equipment must have the vehicle emission control information and fuel labels we require under 40 CFR 86.007–35.

(5) You must add a permanent supplemental label to the equipment in a position where it will remain clearly visible. In the supplemental label, do the following:

(i) Include the heading: "NONROAD ENGINE EMISSION CONTROL INFORMATION".

(ii) Include your full corporate name and trademark. You may instead include the full corporate name and trademark of another company you choose to designate.

(iii) State: "THIS VEHICLE WAS ADAPTED FOR NONROAD USE WITHOUT AFFECTING ITS EMISSION CONTROLS. THE EMISSION-CONTROL SYSTEM DEPENDS ON THE USE OF FUEL MEETING SPECIFICATIONS THAT APPLY FOR MOTOR-VEHICLE APPLICATIONS. OPERATING THE ENGINE ON OTHER FUELS MAY BE A VIOLATION OF FEDERAL LAW.".

(iv) State the date you finished modifying the vehicle (month and year), if applicable.

(6) The original and supplemental labels must be readily visible in the fully assembled equipment.

(7) Send the Designated Compliance Officer a signed letter by the end of each calendar year (or less often if we tell you) with all the following information:

(i) Identify your full corporate name, address, and telephone number.

(ii) List the equipment models you expect to produce under this exemption in the coming year.

(iii) State: "We produce each listed engine or equipment model for nonroad application without making any changes that could increase its certified emission levels, as described in 40 CFR 1039.610.".

(e) *Failure to comply.* If your engines, vehicles, or equipment do not meet the criteria listed in paragraph (d) of this section, the engines will be subject to the standards, requirements, and prohibitions of this part 1039, and the certificate issued under 40 CFR part 86 will not be deemed to also be a certificate issued under this part 1039. Introducing these engines into commerce without a valid exemption or certificate of conformity under this part violates the prohibitions in 40 CFR 1068.101(a)(1).

(f) *Data submission.* We may require you to send us emission test data on any applicable nonroad duty cycles.

§ 1039.615 What special provisions apply to engines using noncommercial fuels?

In § 1039.115(e), we generally require that engines meet emission standards for any adjustment within the full range of any adjustable parameters. For engines that use noncommercial fuels significantly different than the specified test fuel of the same type, you may ask to use the parameter-adjustment provisions of this section instead of those in § 1039.115(e). Engines certified under this section must be in a separate engine family.

(a) If we approve your request, the following provisions apply:

(1) You must certify the engine using the test fuel specified in § 1039.501.

(2) You may produce the engine without limits or stops that keep the engine adjusted within the certified range.

(3) You must specify in-use adjustments different than the adjustable settings appropriate for the specified test fuel, consistent with the provisions of paragraph (b)(1) of this section.

(b) To produce engines under this section, you must do the following:

(1) Specify in-use adjustments needed so the engine's level of emission control for each regulated pollutant is equivalent to that from the certified configuration.

(2) Add the following information to the emission control information label specified in § 1039.135:

(i) Include instructions describing how to adjust the engine to operate in a way that maintains the effectiveness of the emission-control system.

(ii) State: "THIS ENGINE IS CERTIFIED TO OPERATE IN APPLICATIONS USING NONCOMMERCIAL FUEL. MALADJUSTMENT OF THE ENGINE IS A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.".

(3) Keep records to document the destinations and quantities of engines produced under this section.

§ 1039.620 What are the provisions for exempting engines used solely for competition?

The provisions of this section apply for new engines built on or after January 1, 2006.

(a) Equipment manufacturers may use uncertified engines if the vehicles or equipment in which they are installed will be used solely for competition.

(b) The definition of nonroad engine in 40 CFR 1068.30 excludes engines used solely for competition. These engines are not required to comply with this part 1039 or 40 CFR part 89, but 40 CFR 1068.101 prohibits the use of competition engines for noncompetition purposes.

(c) We consider a vehicle or piece of equipment to be one that will be used solely for competition if it has features that are not easily removed that would make its use other than in competition unsafe, impractical, or highly unlikely.

(d) As an engine manufacturer, your engine is exempt without our prior approval if you have a written request for an exempted engine from the equipment manufacturer showing the basis for believing that the equipment will be used solely for competition. You must permanently label engines exempted under this section to clearly indicate that they are to be used solely for competition. Failure to properly label an engine will void the exemption.

(e) We may discontinue an exemption under this section if we find that engines are not used solely for competition.

§ 1039.625 What requirements apply under the program for equipment-manufacturer flexibility?

The provisions of this section allow equipment manufacturers to produce equipment with engines that are subject to less stringent emission standards after the Tier 4 emission standards begin to apply. To be eligible to use these provisions, you must follow all the instructions in this section. *See* 40 CFR 89.102(d) and (e) for provisions that apply to equipment produced while Tier 1, Tier 2, or Tier 3 standards apply. *See* § 1039.626 for requirements that apply specifically to companies that manufacture equipment outside the United States and to companies that import such equipment without manufacturing it. Engines and equipment you produce under this section are exempt from the prohibitions in 40 CFR 1068.101(a)(1), subject to the provisions of this section.

(a) *General.* If you are an equipment manufacturer, you may introduce into commerce in the United States limited numbers of nonroad equipment with engines exempted under this section. You may use the exemptions in this section only if you have primary responsibility for designing and manufacturing equipment and your manufacturing procedures include installing some engines in this equipment. Consider all U.S.-directed equipment sales in showing that you meet the requirements of this section, including those from any parent or subsidiary companies and those from any other companies you license to produce equipment for you. If you produce a type of equipment that has more than one engine, count each engine separately. These provisions are available over the following periods:

(1) These provisions are available for the years shown in the following table, except as provided in paragraph (a)(2) of this section:

TABLE 1 OF § 1039.625.—GENERAL AVAILABILITY OF ALLOWANCES

Power category	Calendar years
kW < 19	2008–2014
19 ≤ kW < 56	2008–2014
56 ≤ kW < 130	2012–2018
130 ≤ kW ≤ 560	2011–2017
kW < 560	2011–2017

(2) If you do not use any allowances in a power category before the earliest dates shown in the following table, you may delay the start of the seven-year period for using allowances under this section as follows:

TABLE 2 OF § 1039.625.—AVAILABILITY OF DELAYED ALLOWANCES

Power category	Calendar years
kW < 19	
19 ≤ kW < 56	2012–2018
56 ≤ kW < 130	2014–2020
130 ≤ kW ≤ 560	2014–2020
kW > 560	2015–2021

(b) *Allowances.* You may choose one of the following options for each power category to produce equipment with exempted engines under this section, except as allowed under § 1039.627:

(1) *Percent-of-production allowances.* You may produce a certain number of units with exempted engines calculated using a percentage of your total sales within a power category relative to your total U.S.-directed production volume. The sum of these percentages within a power category during the seven-year period specified in paragraph (a) of this section may not exceed 80 percent, except as allowed under paragraph (b)(2) or (m) of this section.

(2) *Small-volume allowances.* You may determine an alternate allowance for a specific number of exempted engines under this section using one of the following approaches for your U.S.-directed production volumes:

(i) You may produce up to 700 units with exempted engines within a power category during the seven-year period specified in paragraph (a) of this section, with no more than 200 units in any single year within a power category, except as provided in paragraph (m) of this section. Engines within a power category that are exempted under this section must be from a single engine family within a given year.

(ii) For engines below 130 kW, you may produce up to 525 units with exempted engines within a power category during the seven-year period specified in paragraph (a) of this section, with no more than 150 units in any single year within a power category, except as provided in paragraph (m) of this section. For engines at or above 130 kW, you may produce up to 350 units with exempted engines within a power category during the seven-year period, with no more than 100 units in any single year within a power category. Exemptions under this paragraph (b)(2)(ii) may apply to engines from multiple engine families in a given year.

(c) *Percentage calculation.* Calculate for each calendar year the percentage of equipment with exempted engines from your total U.S.-directed production within a power category if you need to show that you meet the percent-of-production allowances in paragraph (b)(1) of this section.

(d) *Inclusion of engines not subject to Tier 4 standards.* The following provisions apply to engines that are not subject to Tier 4 standards:

(1) If you use the provisions of § 1068.105(a) to use up your inventories of engines not certified to new emission standards, do not include these units in your count of equipment with exempted engines under paragraph (b) of this section. However, you may include these units in your count of total equipment you produce for the given year for the percentage calculation in paragraph (b)(1) of this section.

(2) If you install engines that are exempted from the Tier 4 standards for any reason, other than for equipment-manufacturer allowances under this section, do not include these units in your count of exempted engines under paragraph (b) of this section. However, you may include these units in your count of total equipment you produce for the given year for the percentage calculation in paragraph (b)(1) of this section. For example, if we grant a hardship exemption for the engine manufacturer, you may count these as compliant engines under this section. This paragraph (d)(2) applies only if the engine has a permanent label describing why it is exempted from the Tier 4 standards.

(3) Do not include equipment using model year 2008 or 2009 engines certified under the provisions of § 1039.101(c) in your count of equipment using exempted engines. However, you may include these units in your count of total equipment you produce for the given year for the percentage calculation in paragraph (b)(1) of this section.

(4) You may start using the allowances under this section for engines that are not yet subject to Tier 4 standards, as long as the seven-year period for using allowances under the Tier 2 or Tier 3 program has expired (see 40 CFR 89.102(d)). Table 3 of this section shows the years for which this applies. To use these early allowances, you must use engines that meet the emission standards described in paragraph (e) of this section. You must also count these units or calculate these percentages as described in paragraph (c) of this section and apply them toward the total number or percentage of equipment with exempted engines we allow for the Tier 4 standards as described in paragraph (b) of this section. The maximum number of cumulative early allowances under this paragraph (d)(4) is 10 percent under the percent-of-production allowance or 100 units under the small-volume allowance. For example, if you produce 5 percent of your equipment with engines between 130 and 560 kW that use allowances under this paragraph (d)(4) in 2009, you may use up to an additional 5 percent of your allowances in 2010. If you use allowances for 5 percent of your equipment in both 2009 and 2010, your 80 percent allowance for 2011–2017 in the 130–560 kW power category decreases to 70 percent. Manufacturers using allowances under this paragraph (d)(4) must comply with the notification and reporting requirements specified in paragraph (g) of this section.

TABLE 3 OF § 1039.625.—YEARS FOR EARLY ALLOWANCES

Maximum engine power	Calendar years
kW < 19	2007
19 ≤ kW < 37	2006–2011
37 ≤ kW < 56	2011
56 ≤ kW < 75	2011
75 ≤ kW < 130	2010–2011
130 ≤ kW < 225	2010
225 ≤ kW < 450	2008–2010
450 ≤ kW ≤ 560	2009–2010
KW > 560	

(e) *Standards.* If you produce equipment with exempted engines under this section, the engines must meet emission standards at least as stringent as the following:

(1) If you are using the provisions of paragraph (d)(4) of this section, engines must meet the applicable Tier 1 emission standards described in § 89.112.

(2) If you are using the provisions of paragraph (a)(2) of this section, engines must be certified under this part 1039 as follows:

Engines in the following power category . . .	Must meet all standards and requirements that applied in the following model year . . .
(i) 19 ≤ kW < 56	2008
(ii) 56 ≤ kW < 130	2012
(iii) 130 ≤ kW ≤ 560	2011
(iv) kW > 560	2011

(3) In all other cases, engines at or above 37 kW and at or below 560 kW must meet the appropriate Tier 3 standards described in § 89.112. Engines below 37 kW and engines above 560 kW must meet the appropriate Tier 2 standards described in § 89.112.

(f) *Equipment labeling.* You must add a permanent label, written legibly in English, to the engine or another readily visible part of each piece of equipment you produce with exempted engines under this section. This label, which supplements the engine manufacturer's emission control information label, must include at least the following items:

(1) The label heading "EMISSION CONTROL INFORMATION".

(2) Your corporate name and trademark.

(3) The calendar year in which the equipment is manufactured.

(4) The name, e-mail address, and phone number of a person to contact for further information.

(5) The following statement:

THIS EQUIPMENT [or identify the type of equipment] HAS AN ENGINE THAT MEETS U.S. EPA EMISSION STANDARDS UNDER 40 CFR 1039.625.

(g) *Notification and reporting.* You must notify us of your intent to use the provisions of this section and send us an annual report to verify that you are not exceeding the allowances, as follows:

(1) Before January 1 of the first year you intend to use the provisions of this section, send the Designated Compliance Officer and the Designated Enforcement Officer a written notice of your intent, including:

(i) Your company's name and address, and your parent company's name and address, if applicable.

(ii) Whom to contact for more information.

(iii) The calendar years in which you expect to use the exemption provisions of this section.

(iv) The name and address of the company that produces the engines you will be using for the equipment exempted under this section.

(v) Your best estimate of the number of units in each power category you will produce under this section and whether you intend to comply under paragraph (b)(1) or (b)(2) of this section.

(vi) The number of units in each power category you have sold in previous calendar years under 40 CFR 89.102(d).

(2) For each year that you use the provisions of this section, send the Designated Compliance Officer and the Designated Enforcement Officer a written report by March 31 of the following year. Include in your report the total number of engines you sold in the preceding year for each power category, based on actual U.S.-directed production information. Also identify the percentages of U.S.-directed production that correspond to the number of units in each power category and the cumulative numbers and percentages of units for all the units you have sold under this section for each power category. You may omit the percentage figures if you include in the report a statement that you will not be using the percent-of-production allowances in paragraph (b)(1) of this section.

(h) *Recordkeeping.* Keep the following records of all equipment with exempted engines you produce under this section for at least five full years after the final year in which allowances are available for each power category:

(1) The model number, serial number, and the date of manufacture for each engine and piece of equipment.

(2) The maximum power of each engine.

(3) The total number or percentage of equipment with exempted engines, as described in paragraph (b) of this section and all documentation supporting your calculation.

(4) The notifications and reports we require under paragraph (g) of this section.

(i) *Enforcement.* Producing more exempted engines or equipment than we allow under this section or installing engines that do not meet the emission standards of paragraph (e) of this section violates the prohibitions in 40 CFR 1068.101(a)(1). You must give us the records we require under this section if we ask for them (*see* 40 CFR 1068.101(a)(2)).

(j) *Provisions for engine manufacturers.* As an engine manufacturer, you may produce exempted engines as needed under this section. You do not have to request this exemption for your engines, but you must have written assurance from equipment manufacturers that they need a certain number of exempted engines under this section. Send us an annual report of the engines you produce under this section, as described in

§ 1039.250(a). For engines produced under the provisions of paragraph (a)(2) of this section, you must certify the engines under this part 1039. For all other exempt engines, the engines must meet the emission standards in paragraph (e) of this section and you must meet all the requirements of § 1039.260. If you show under § 1039.260(c) that the engines are identical in all material respects to engines that you have previously certified to one or more FELs above the standards specified in paragraph (e) of this section, you must supply sufficient credits for these engines. Calculate these credits under subpart H of this part using the previously certified FELs and the alternate standards. You must meet the labeling requirements in 40 CFR 89.110, but add the following statement instead of the compliance statement in 40 CFR 89.110(b)(10):

THIS ENGINE MEETS U.S. EPA EMISSION STANDARDS UNDER 40 CFR 1039.625. SELLING OR INSTALLING THIS ENGINE FOR ANY PURPOSE OTHER THAN FOR THE EQUIPMENT FLEXIBILITY PROVISIONS OF 40 CFR 1039.625 MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.

(k) *Other exemptions. See* 40 CFR 1068.255 for exemptions based on hardship for equipment manufacturers and secondary engine manufacturers.

(l) [Reserved]

(m) *Additional exemptions for technical or engineering hardship.* You may request additional engine allowances under paragraph (b)(1) of this section for 19–560 kW power categories or, if you are a small equipment manufacturer, under paragraph (b)(2) of this section for engines at or above 19 and below 37 kW. However, you may use these extra allowances only for those equipment models for which you, or an affiliated company, do not also produce the engine. After considering the circumstances, we may permit you to introduce into commerce equipment with such engines that do not comply with Tier 4 emission standards, as follows:

(1) We may approve additional exemptions if extreme and unusual circumstances that are clearly outside your control and that could not have been avoided with reasonable discretion have resulted in technical or engineering problems that prevent you from meeting the requirements of this part. You must show that you exercised prudent planning and have taken all reasonable steps to minimize the scope of your request for additional allowances.

(2) To apply for exemptions under this paragraph (m), send the Designated Compliance Officer and the Designated Enforcement Officer a written request as soon as possible before you are in violation. In your request, include the following information:

(i) Describe your process for designing equipment.

(ii) Describe how you normally work cooperatively or concurrently with your engine supplier to design products.

(iii) Describe the engineering or technical problems causing you to request the exemption and explain why you have not been able to solve them. Describe the extreme and unusual circumstances that led to these problems and explain how they were unavoidable.

(iv) Describe any information or products you received from your engine supplier related to equipment design—such as written specifications, performance data, or prototype engines—and when you received it.

(v) Compare the design processes of the equipment model for which you need additional exemptions and that for other models for which you do not need additional exemptions. Explain the technical differences that justify your request.

(vi) Describe your efforts to find and use other compliant engines, or otherwise explain why none is available.

(vii) Describe the steps you have taken to minimize the scope of your request.

(viii) Include other relevant information. You must give us other relevant information if we ask for it.

(ix) Estimate the increased percent of production you need for each equipment model covered by your request, as described in paragraph (m)(3) of this section. Estimate the increased number of allowances you need for each equipment model covered by your request, as described in paragraph (m)(4) of this section.

(3) We may approve your request to increase the allowances under paragraph (b)(1) of this section, subject to the following limitations:

(i) The additional allowances will not exceed 70 percent for each power category.

(ii) You must use up the allowances under paragraph (b)(1) of this section before using any additional allowance under this paragraph (m).

(iii) Any allowances we approve under this paragraph (m)(3) expire 24 months after the provisions of this section start for a given power category, as described in paragraph (a) of this section. You may use these allowances only for the specific equipment models covered by your request.

(4) We may approve your request to increase the allowances for the 19–56 kW power category under paragraph (b)(2) of this section, subject to the following limitations:

(i) You are eligible for additional allowances under this paragraph (m)(4) only if you are a small equipment manufacturer and you do not use the provisions of paragraph (m)(3) of this section to obtain additional allowances for the 19–56 kW power category.

(ii) You must use up all the available allowances for the 19–56 kW power category under paragraph (b)(2) of this section in a given year before using any additional allowances under this paragraph (m)(4).

(iii) Base your request only on equipment you produce with engines at or above 19 kW and below 37 kW. You may use any additional allowances only for equipment you produce with engines at or above 19 kW and below 37 kW.

(iv) The total allowances under either paragraph (b)(2)(i) or (ii) of this section for the 19–56 kW power category will not exceed 1,100 units.

(v) Any allowances we approve under this paragraph (m)(4) expire 36 months after the provisions of this section start for this power category, as described in paragraph (a) of this section. These additional allowances are not subject to the annual limits specified in paragraph (b)(2) of this section. You may use these allowances only for the specific equipment models covered by your request.

(5) For purposes of this paragraph (m), *small equipment manufacturer* means a small-business equipment manufacturer that had annual U.S.-directed production volume of equipment using nonroad diesel engines between 19 and 56 kW of no more than 3,000 units in 2002 and all earlier calendar years, and has 750 or fewer employees (500 or fewer employees for nonroad equipment manufacturers that produce no construction equipment or industrial trucks). For manufacturers owned by a parent company, the production limit applies to the production of the parent company and all its subsidiaries and the employee limit applies to the total number of employees of the parent company and all its subsidiaries.

§ 1039.626 What special provisions apply to equipment imported under the equipment-manufacturer flexibility program?

This section describes requirements that apply to equipment manufacturers using the provisions of § 1039.625 for equipment produced outside the United States. Note that § 1039.625 limits these provisions to equipment manufacturers that install some engines and have primary responsibility for designing and manufacturing equipment. Companies that import equipment into the United States without meeting these criteria are not eligible for these allowances. Such importers may import equipment with exempted engines only as described in paragraph (b) of this section.

(a) As a foreign equipment manufacturer, you or someone else may import equipment with exempted engines under this section if you comply with the provisions in § 1039.625 and commit to the following:

(1) Give any EPA inspector or auditor complete and immediate access to inspect and audit, as follows:

(i) Inspections and audits may be announced or unannounced.

(ii) Inspections and audits may be by EPA employees or EPA contractors.

(iii) You must provide access to any location where—

(A) Any nonroad engine, equipment, or vehicle is produced or stored.

(B) Documents related to manufacturer operations are kept.

(C) Equipment, engines, or vehicles are tested or stored for testing.

(iv) You must provide any documents requested by an EPA inspector or auditor that are related to matters covered by the inspections or audit.

(v) EPA inspections and audits may include review and copying of any documents related to demonstrating compliance with the exemptions in § 1039.625.

(vi) EPA inspections and audits may include inspection and evaluation of complete or incomplete equipment, engines, or vehicles, and interviewing employees.

(vii) You must make any of your employees available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) You must provide English language translations of any documents to an EPA inspector or auditor, on request, within 10 working days.

(ix) You must provide English-language interpreters to accompany EPA inspectors and auditors, on request.

(2) Name an agent for service of process located in the District of Columbia. Service on this agent constitutes service on you or any of your officers or employees for any action by EPA or otherwise by the United States related to the requirements of this part.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act.

(4) The substantive and procedural laws of the United States shall apply to any civil or criminal enforcement action against you or any of your officers or employees related to the provisions of this section.

(5) Provide the notification required by § 1039.625(g). Include in the notice of intent in § 1039.625(g)(1) a commitment to comply with the requirements and obligations of § 1039.625 and this section. This commitment must be signed by the owner or president.

(6) You, your agents, officers, and employees must not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) By submitting notification of your intent to use the provisions of § 1039.625, producing and exporting for resale to the United States nonroad equipment under this section, or taking other actions to comply with the requirements of this part, you, your agents, officers, and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States as described in 28 U.S.C. 1605(a)(2), without limitation based on sovereign immunity, for conduct that violates the requirements applicable to you under this part 1039—including such conduct that violates 18 U.S.C. 1001, 42 U.S.C. 7413(c)(2), or other applicable provisions of the Clean Air Act with respect to actions instituted against you and your agents, officers, and employees in any court or other tribunal in the United States.

(8) Any report or other document you submit to us must be in the English language, or include a complete translation in English.

(9) You must post a bond to cover any potential enforcement actions under the Clean Air Act before you or anyone else imports your equipment under this section, as follows:

(i) The value of the bond is based on the per-engine bond values shown in Table 1 of this section and on the highest number of engines in each power category you produce in any single calendar year under the provisions of § 1039.625. For example, if you have projected U.S.-directed production volumes of 100 exempt engines in the 19–56 kW power category and 300 exempt engines in the 56–130 kW power category in 2013, the appropriate bond amount is $180,000. If your estimated or actual engine imports increase beyond the level appropriate for your current bond payment, you must post additional bond to reflect the increased sales within 90 days after you change your estimate or determine the actual sales. You may not decrease your bond.

(ii) You may meet the bond requirements of this section with any of the following methods:

(A) Get a bond from a third-party surety that is cited in the U.S. Department of Treasury Circular 570, "Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds and as Acceptable Reinsuring Companies." Maintain this bond for five years after the applicable allowance period expires, or five years after you use up all the available allowances under § 1039.625, whichever comes first.

(B) Get the Designated Enforcement Officer to approve a waiver from the bonding requirement, as long as you can show that you have assets of an appropriate liquidity and value readily available in the United States.

(iii) If you forfeit some or all of your bond in an enforcement action, you must post any appropriate bond for continuing importation within 90 days after you forfeit the bond amount.

TABLE 1 OF § 1039.626.—PER-ENGINE BOND VALUES

For engines with maximum engine power falling in the following ranges . . .	The per-engine bond value is . . .
kW < 19	$150
19 ≤ kW < 56	300
56 ≤ kW < 130	500
130 ≤ kW < 225	1,000
225 ≤ kW < 450	3,000
kW ≥ 450	8,000

(iv) You will forfeit the proceeds of the bond posted under this paragraph (a)(9) if you need to satisfy any United States administrative final order or judicial judgment against you arising from your conduct in violation of this part 1039, including such conduct that violates 18 U.S.C. 1001, 42 U.S.C. 7413(c)(2), or other applicable provisions of the Clean Air Act.

(b) The provisions of this paragraph (b) apply to importers that do not install engines into equipment and do not have primary responsibility for designing and manufacturing equipment. Such importers may import equipment with engines exempted under § 1039.625 only if each engine is exempted under an allowance provided to an equipment manufacturer meeting the requirements of § 1039.625 and this section. You must notify us of your intent to use the provisions of this section and send us an annual report, as follows:

(1) Before January 1 of the first year you intend to use the provisions of this section, send the Designated Compliance Officer and the Designated Enforcement Officer a written notice of your intent, including:

(i) Your company's name and address, and your parent company's name and address, if applicable.

(ii) The name and address of the companies that produce the equipment and engines you will be importing under this section.

(iii) Your best estimate of the number of units in each power category you will import under this section in the upcoming calendar year, broken down by equipment manufacturer and power category.

(iv) The number of units in each power category you have imported in previous calendar years under 40 CFR 89.102(d).

(2) For each year that you use the provisions of this section, send the Designated Compliance Officer and the Designated Enforcement Officer a written report by March 31 of the following year. Include in your report the total number of engines you imported under this section in the preceding calendar year, broken down by engine manufacturer and by equipment manufacturer.

§ 1039.627 What are the incentives for equipment manufacturers to use cleaner engines?

This section allows equipment manufacturers to generate additional allowances under the provisions of § 1039.625 by producing equipment using engines at or above 19 kW certified to specified levels earlier than otherwise required.

(a) For early-compliant engines to generate offsets for use under this section, the following general provisions apply:

(1) The engine manufacturer must comply with the provisions of § 1039.104(a)(1) for the offset-generating engines.

(2) Engines you install in your equipment after December 31 of the years specified in § 1039.104(a)(1) do not generate allowances under this section, even if the engine manufacturer generated offsets for that engine under § 1039.104(a).

(3) Offset-generating engines must be certified to the following standards under this part 1039:

If the engine's maximum power is . . .	And you install . . .	Certified early to the . . .	You may reduce the number of engines in the same power category that are required to meet the . . .	In later model years by . . .
(i) kW ≥ 19	One engine	Emissions standards in § 1039.101	Standards in Tables 2 through 7 of § 1039.102 or in § 1039.101.	One engine.
(ii) 56 ≤ kW < 130	Two engines	NO_X standards in § 1039.102(d)(1), and NMHC standard of 0.19 g/kW-hr, a PM standard of 0.02 g/kW-hr, and a CO standard of 5.0 g/kW-hr.	Standards in Tables 2 through 7 of § 1039.102 or in § 1039.101.	One engine.
(iii) 130 ≤ kW < 560	Two engines	NO_X standards in § 1039.102(d)(2), an NMHC standard of 0.19 g/kW-hr, a PM standard of 0.02 g/kW-hr, and a CO standard of 3.5 g/kW-hr.	Standards in Tables 2 through 7 of § 1039.102 or in § 1039.101.	One engine.

(b) *Using engine offsets.* (1) You may use engine offsets generated under paragraph (a) of this section to generate additional allowances under § 1039.625, as follows:

(i) For each engine offset, you may increase the number of available allowances under § 1039.625(b) for that power category by one engine for the years indicated.

(ii) For engines in 56–560 kW power categories, you may transfer engine offsets across power categories within this power range. Calculate the number of additional allowances by scaling the number of generated engine offsets according to the ratio of engine power for offset and allowance engines. Make this calculation for all your offset engines for which you will transfer offsets under this paragraph (b)(1)(ii), then round the result to determine the total number of available power-weighted allowances. For example, if you generate engine offsets for 75 500-kW engines, you may generate up to 37,500 kW-engines of power-weighted allowances. You may apply this to 375 100-kW engines or any other combination that totals 37,500 kW-engines.

(2) You may decline to use the offsets. If you decline, the engine manufacturer may use the provisions of § 1039.104(a)(1).

(c) *Limitation on offsets for engines above 560 kW.* For engines above 560 kW, you must track how many engines you install in generator sets and how many you install in other applications under the provisions of this section. Offsets from generator-set engines may be used only for generator-set engines. Offsets from engines for other applications may be used only for other applications besides generator sets.

(d) *Reporting.* When you submit your first annual report under § 1039.625(g), include the following additional information related to the engines you use to generate offsets under this section:

(1) The name of each engine family involved.

(2) The number of engines from each power category.

(3) The maximum engine power of each engine.

(4) For engines above 560 kW, whether you use engines certified to the standards for generator-set engines.

(e) *In-use fuel.* If the engine manufacturer certifies using ultra low-sulfur diesel fuel, you must take steps to ensure that the in-use engines in the family will use diesel fuel with a sulfur concentration no greater than 15 ppm. For example, selling equipment only into applications where the operator commits to a central-fueling facility with ultra low-sulfur diesel fuel throughout its lifetime would meet this requirement.

§ 1039.630 What are the economic hardship provisions for equipment manufacturers?

If you qualify for the economic hardship provisions specified in 40 CFR 1068.255, we may approve your hardship application subject to the following additional conditions:

(a) You must show that you have used up the allowances to produce equipment with exempted engines under § 1039.625.

(b) You may produce equipment under this section for up to 12 months total (or 24 months total for small-volume manufacturers).

§ 1039.635 What are the hardship provisions for engine manufacturers?

If you qualify for the hardship provisions specified in 40 CFR 1068.245, we may approve a period of delayed compliance for up to one model year total (or two model years total for small-volume manufacturers). If you qualify for the hardship provisions specified in 40 CFR 1068.250 for small-volume manufacturers, we may approve a period of delayed compliance for up to two model years total.

§ 1039.640 What special provisions apply to branded engines?

The following provisions apply if you identify the name and trademark of another company instead of your own on your emission control information label, as provided by § 1039.135(c)(2):

(a) You must have a contractual agreement with the other company that obligates that company to take the following steps:

(1) Meet the emission warranty requirements that apply under § 1039.120. This may involve a separate agreement involving reimbursement of warranty-related expenses.

(2) Report all warranty-related information to the certificate holder.

(b) In your application for certification, identify the company whose trademark you will use and describe the arrangements you have made to meet your requirements under this section.

(c) You remain responsible for meeting all the requirements of this chapter, including warranty and defect-reporting provisions.

§ 1039.645 What special provisions apply to engines used for transportation refrigeration units?

Manufacturers may choose to use the provisions of this section for engines used in transportation refrigeration units (TRUs). The operating restrictions and characteristics in paragraph (f) of this section define engines that are not used in TRUs. All provisions of this part apply for TRU engines, except as specified in this section.

(a) You may certify engines under this section with the following special provisions:

(1) The engines are not subject to the transient emission standards of subpart B of this part.

(2) The steady-state emission standards in subpart B of this part apply for emissions measured over the steady-state test cycle described in paragraph (b) of this section instead of the otherwise applicable duty cycle described in § 1039.505.

(b) Measure steady-state emissions using the procedures specified in § 1039.505, except for the duty cycles, as follows:

(1) The following duty cycle applies for discrete-mode testing:

TABLE 1 OF § 1039.645.—DISCRETE-MODE CYCLE FOR TRU ENGINES

Mode number	Engine speed [1]	Observed torque [2]	Weighting factors
1	Maximum test speed	75	0.25
2	Maximum test speed	50	0.25
3	Intermediate test speed	75	0.25
4	Intermediate test speed	50	0.25

[1] Speed terms are defined in 40 CFR part 1065.
[2] The percent torque is relative to the maximum torque at the given engine speed.

(2) The following duty cycle applies for ramped-modal testing:

TABLE 2 OF § 1039.645.—RAMPED-MODAL CYCLE FOR TRU ENGINES

RMC mode	Time in mode (seconds)	Engine speed [1]	Torque (percent) [2 3]
1a Steady-state	290	Intermediate Speed	75.
1b Transition	20	Intermediate Speed	Linear Transition.
2a Steady-state	280	Intermediate Speed	50.
2b Transition	20	Linear Transition	Linear Transition.
3a Steady-state	280	Maximum Test Speed	75.
3b Transition	20	Maximum Test Speed	Linear Transition.
4 Steady-state	290	Maximum Test Speed	50

[1] Speed terms are defined in 40 CFR part 1065.
[2] The percent torque is relative to the maximum torque at the commanded engine speed.
[3] Advance from one mode to the next within a 20-second transition phase. During the transition phase, command a linear progression from the torque setting of the current mode to the torque setting of the next mode, and simultaneously command a similar linear progression for engine speed if there is a change in speed setting.

(c) Engines certified under this section must be certified in a separate engine family that contains only TRU engines.

(d) You must do the following for each engine certified under this section:

(1) State on the emission control information label: "THIS ENGINE IS CERTIFIED TO OPERATE ONLY IN TRANSPORTATION REFRIGERATION UNITS. INSTALLING OR USING THIS ENGINE IN ANY OTHER APPLICATION MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.".

(2) State in the emission-related installation instructions all steps necessary to ensure that the engine will operate only in the modes covered by the test cycle described in this section.

(3) Keep records to document the destinations and quantities of engines produced under this section.

(e) All engines certified under this section must comply with NTE standards, as described in § 1039.101 or § 1039.102 for the applicable model year, except that the NTE standards are not limited with respect to operating speeds and loads. In your application for certification, certify that all the engines in the engine family comply with the not-to-exceed emission standards for all normal operation and use. The deficiency provisions of § 1039.104(d) do not apply to these engines. This paragraph (e) applies whether or not the engine would otherwise be subject to NTE standards.

(f) An engine is not considered to be used in a TRU if any of the following is true:

(1) The engine is installed in any equipment other than refrigeration units for railcars, truck trailers, or other freight vehicles.

(2) The engine operates in any mode not covered by the test cycle described in this section, except as follows:

(i) The engine may operate briefly at idle. Note, however, that TRU engines must meet NTE emission standards under any type of operation, including idle, as described in paragraph (e) of this section.

(ii) The engine may have a minimal amount of transitional operation between two allowable modes. As an example, a thirty-second transition period would clearly not be considered minimal.

(iii) The engine as installed may experience up to a 2-percent decrease in load at a given setpoint over any 10-minute period, and up to a 15-percent decrease in load at a given setpoint over any 60-minute period.

(3) The engine is sold in a configuration that allows the engine to operate in any mode not covered by the test cycle described in this section. For example, this section does not apply to an engine sold without a governor limiting operation only to those modes covered by the test cycle described in this section.

(4) The engine is subject to Tier 3 or earlier standards, or phase-out Tier 4 standards.

§ 1039.650 [Reserved]

§ 1039.655 What special provisions apply to engines sold in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) The prohibitions in § 1068.101(a)(1) do not apply to an engine if the following conditions are met:

(1) The engine is intended for use and will be used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands.

(2) The engine meets the latest applicable emission standards in 40 CFR 89.112.

(3) You meet all the requirements of § 1039.260.

(b) If you introduce an engine into commerce in the United States under this section, you must meet the labeling requirements in 40 CFR 89.110, but add the following statement instead of the compliance statement in 40 CFR 89.110(b)(10):

THIS ENGINE DOES NOT COMPLY WITH U.S. EPA TIER 4 EMISSION REQUIREMENTS. IMPORTING THIS ENGINE INTO THE UNITED STATES OR ANY TERRITORY OF THE UNITED STATES EXCEPT GUAM, AMERICAN SAMOA, OR THE COMMONWEALTH OF THE NORTHERN MARIANA ISLANDS MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.

(c) Introducing into commerce an engine exempted under this section in any state or territory of the United States other than Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands, throughout its lifetime, violates the prohibitions in 40 CFR 1068.101(a)(1), unless it is exempt under a different provision.

§ 1039.660 What special provisions apply to Independent Commercial Importers?

Under § 1039.801, certain engines are considered to be new engines when they are imported into the United States, even if they have previously been used outside the country. Independent Commercial Importers may use the provisions of 40 CFR part 89, subpart G, and 40 CFR 89.906(b) to receive a certificate of conformity for engines meeting all the requirements of this part 1039.

Subpart H—Averaging, Banking, and Trading for Certification

§ 1039.701 General provisions.

(a) You may average, bank, and trade (ABT) emission credits for purposes of certification as described in this subpart to show compliance with the standards of this part. Participation in this program is voluntary.

(b) Section 1039.740 restricts the use of emission credits to certain averaging sets.

(c) The definitions of Subpart I of this part apply to this subpart. The following definitions also apply:

(1) *Actual emission credits* means emission credits you have generated that we have verified by reviewing your final report.

(2) *Averaging set* means a set of engines in which emission credits may be exchanged only with other engines in the same averaging set.

(3) *Broker* means any entity that facilitates a trade of emission credits between a buyer and seller.

(4) *Buyer* means the entity that receives emission credits as a result of a trade.

(5) *Reserved emission credits* means emission credits you have generated that we have not yet verified by reviewing your final report.

(6) *Seller* means the entity that provides emission credits during a trade.

(7) *Standard* means the emission standard that applies under subpart B of this part for engines not participating in the ABT program of this subpart.

(8) *Trade* means to exchange emission credits, either as a buyer or seller.

(d) You may not use emission credits generated under this subpart to offset any emissions that exceed an FEL or standard. This applies for all testing, including certification testing, in-use testing, selective enforcement audits, and other production-line testing. However, if emissions from an engine exceed an FEL or standard (for example, during a selective enforcement audit), you may use emission credits to recertify the engine family with a higher FEL that applies only to future production.

(e) Engine families that use emission credits for one or more pollutants may not generate positive emission credits for another pollutant.

(f) Emission credits may be used in the model year they are generated or in future model years. Emission credits may not be used for past model years.

(g) You may increase or decrease an FEL during the model year by amending your application for certification under § 1039.225. The new FEL may apply only to engines you have not already introduced into commerce. Each engine's emission control information label must include the applicable FELs.

§ 1039.705 How do I generate and calculate emission credits?

The provisions of this section apply separately for calculating emission credits for NO_X, NO_X+NMHC, or PM.

(a) Calculate positive emission credits for an engine family that has an FEL below the otherwise applicable standard. Calculate negative emission credits for an engine family that has an FEL above the otherwise applicable standard.

(b) For each participating engine family, calculate positive or negative emission credits relative to the otherwise applicable emission standard. Round calculated emission credits to the nearest kilogram (kg), using consistent units throughout the following equation:

$$\text{Emission credits (kg)} = (\text{Std} - \text{FEL}) \times (\text{Volume}) \times (\text{AvgPR}) \times (\text{UL}) \times (10^{-3})$$

Where:

Std = the emission standard, in grams per kilowatt-hour, that applies under subpart B of this part for engines not participating in the ABT program of this subpart (the "otherwise applicable standard").

FEL = the family emission limit for the engine family, in grams per kilowatt-hour.

Volume = the number of engines eligible to participate in the averaging, banking, and trading program within the given engine family during the model year, as described in paragraph (c) of this section.

AvgPR = the average maximum engine power of all the engine configurations within an engine family, calculated on a sales-weighted basis, in kilowatts.

UL = the useful life for the given engine family, in hours.

(c) In your application for certification, base your showing of compliance on projected production volumes for engines whose point of first retail sale is in the United States. As described in § 1039.730, compliance with the requirements of this subpart is determined at the end of the model year based on actual production volumes for engines whose point of first retail sale is in the United States. Do not include any of the following engines to calculate emission credits:

(1) Engines exempted under subpart G of this part or under 40 CFR part 1068.

(2) Exported engines.

(3) Engines not subject to the requirements of this part, such as those excluded under § 1039.5.

(4) [Reserved]

(5) Any other engines, where we indicate elsewhere in this part 1039 that they are not to be included in the calculations of this subpart.

§ 1039.710 How do I average emission credits?

(a) Averaging is the exchange of emission credits among your engine families. You may average emission credits only within the same averaging set.

(b) You may certify one or more engine families to an FEL above the applicable standard, subject to the FEL caps and other provisions in subpart B of this part, if you show in your application for certification that your projected balance of all emission-credit transactions in that model year is greater than or equal to zero.

(c) If you certify an engine family to an FEL that exceeds the otherwise applicable standard, you must obtain enough emission credits to offset the engine family's deficit by the due date for the final report required in § 1039.730. The emission credits used to address the deficit may come from your other engine families that generate emission credits in the same model year, from emission credits you have banked, or from emission credits you obtain through trading.

§ 1039.715 How do I bank emission credits?

(a) Banking is the retention of emission credits by the manufacturer generating the emission credits for use in averaging or trading in future model years. You may use banked emission credits only within the averaging set in which they were generated.

(b) In your application for certification, designate any emission credits you intend to bank. These emission credits will be considered reserved credits. During the model year and before the due date for the final report, you may redesignate these emission credits for averaging or trading.

(c) You may use banked emission credits from the previous model year for averaging or trading before we verify them, but we may revoke these emission credits if we are unable to verify them after reviewing your reports or auditing your records.

(d) Reserved credits become actual emission credits only when we verify them in reviewing your final report.

§ 1039.720 How do I trade emission credits?

(a) Trading is the exchange of emission credits between manufacturers. You may use traded emission credits for averaging, banking, or further trading transactions. Traded emission credits may be used only within the averaging set in which they were generated.

(b) You may trade actual emission credits as described in this subpart. You may also trade reserved emission credits, but we may revoke these emission credits based on our review of your records or reports or those of the company with which you traded emission credits.

(c) If a negative emission credit balance results from a transaction, both the buyer and seller are liable, except in cases we deem to involve fraud. See § 1039.255(e) for cases involving fraud. We may void the certificates of all engine families participating in a trade that results in a manufacturer having a negative balance of emission credits. See § 1039.745.

§ 1039.725 What must I include in my application for certification?

(a) You must declare in your application for certification your intent to use the provisions of this subpart for each engine family that will be certified using the ABT program. You must also declare the FELs you select for the engine family for each pollutant for which you are using the ABT program. Your FELs must comply with the specifications of subpart B of this part, including the FEL caps. FELs must be expressed to the same number of decimal places as the applicable standards.

(b) Include the following in your application for certification:

(1) A statement that, to the best of your belief, you will not have a negative balance of emission credits for any averaging set when all emission credits are calculated at the end of the year.

(2) Detailed calculations of projected emission credits (positive or negative) based on projected production volumes. If your engine family will generate positive emission credits, state specifically where the emission credits will be applied (for example, to which engine family they will be applied in averaging, whether they will be traded, or whether they will be reserved for banking). If you have projected negative emission credits for an engine family, state the source of positive emission credits to offset the negative emission credits. Describe whether the emission credits are actual or reserved and whether they will come from averaging, banking, trading, or a combination of these. Identify from which of your engine families or from which manufacturer the emission credits will come.

§ 1039.730 What ABT reports must I send to EPA?

(a) If any of your engine families are certified using the ABT provisions of this subpart, you must send an end-of-year report within 90 days after the end of the model year and a final report within 270 days after the end of the model year. We may waive the requirement to send the end-of year report, as long as you send the final report on time.

(b) Your end-of-year and final reports must include the following information for each engine family participating in the ABT program:

(1) Engine-family designation.

(2) The emission standards that would otherwise apply to the engine family.

(3) The FEL for each pollutant. If you changed an FEL during the model year, identify each FEL you used and calculate the positive or negative emission credits under each FEL. Also, describe how the applicable FEL can be identified for each engine you produced. For example, you might keep a list of engine identification numbers that correspond with certain FEL values.

(4) The projected and actual production volumes for the model year with a point of retail sale in the United States. If you changed an FEL during the model year, identify the actual production volume associated with each FEL.

(5) Maximum engine power for each engine configuration, and the sales-weighted average engine power for the engine family.

(6) Useful life.

(7) Calculated positive or negative emission credits for the whole engine family. Identify any emission credits that you traded, as described in paragraph (d)(1) of this section.

(c) Your end-of-year and final reports must include the following additional information:

(1) Show that your net balance of emission credits from all your engine families in each averaging set in the applicable model year is not negative.

(2) State whether you will reserve any emission credits for banking.

(3) State that the report's contents are accurate.

(d) If you trade emission credits, you must send us a report within 90 days after the transaction, as follows:

(1) As the seller, you must include the following information in your report:

(i) The corporate names of the buyer and any brokers.

(ii) A copy of any contracts related to the trade.

(iii) The engine families that generated emission credits for the trade, including the number of emission credits from each family.

(2) As the buyer, you must include the following information in your report:

(i) The corporate names of the seller and any brokers.

(ii) A copy of any contracts related to the trade.

(iii) How you intend to use the emission credits, including the number of emission credits you intend to apply to each engine family (if known).

(e) Send your reports electronically to the Designated Compliance Officer using an approved information format. If you want to use a different format, send us a written request with justification for a waiver.

(f) Correct errors in your end-of-year report or final report as follows:

(1) You may correct any errors in your end-of-year report when you prepare the final report, as long as you send us the final report by the time it is due.

(2) If you or we determine within 270 days after the end of the model year that errors mistakenly decrease your balance of emission credits, you may correct the errors and recalculate the balance of emission credits. You may not make these corrections for errors that are determined more than 270 days after the end of the model year. If you report a negative balance of emission credits, we may disallow corrections under this paragraph (f)(2).

(3) If you or we determine anytime that errors mistakenly increase your balance of emission credits, you must correct the errors and recalculate the balance of emission credits.

§ 1039.735 What records must I keep?

(a) You must organize and maintain your records as described in this section. We may review your records at any time.

(b) Keep the records required by this section for eight years after the due date for the end-of-year report. You may use any appropriate storage formats or media, including paper, microfilm, or computer diskettes.

(c) Keep a copy of the reports we require in § 1039.725 and § 1039.730.

(d) Keep the following additional records for each engine you produce that generates or uses emission credits under the ABT program:

(1) Engine family designation.

(2) Engine identification number.

(3) FEL and useful life.

(4) Maximum engine power.

(5) Build date and assembly plant.

(6) Purchaser and destination.

(e) We may require you to keep additional records or to send us relevant information not required by this section.

§ 1039.740 What restrictions apply for using emission credits?

The following restrictions apply for using emission credits:

(a) *Averaging sets.* Emission credits may be exchanged only within an averaging set. For Tier 4 engines, there are two averaging sets—one for engines at or below 560 kW and another for engines above 560 kW.

(b) *Emission credits from earlier tiers of standards.* (1) For purposes of ABT under this subpart, you may not use emission credits generated from engines subject to emission standards under 40 CFR part 89, except as specified in § 1039.102(d)(1) or the following table:

If the maximum power of the credit-generating engine is . . .	And it was certified to the following standards under 40 CFR part 89 . . .	Then you may use those banked credits for the following Tier 4 engines . . .
(i) kW < 19	Tier 2	kW < 19
(ii) 19 ≤ kW < 37	Tier 2	kW ≥ 19
(iii) 37 ≤ kW ≤ 560	Tier 3	kW ≥ 19
(iv) kW > 560	Tier 2	kW ≥ 19

(2) Emission credits generated from marine engines certified under the provisions of 40 CFR part 89 may not be used under this part.

(3) See 40 CFR part 89 for other restrictions that may apply for using emission credits generated under that part.

(c) *NO_X and NO_X+NMHC emission credits.* You may use NO_X emission credits without adjustment to show compliance with NO_X+NMHC standards. You may use NO_X+NMHC emission credits to show compliance with NO_X standards, but you must adjust the NO_X+NMHC emission credits downward by twenty percent when you use them, as shown in the following equation:

$$NO_X \text{ emission credits} = (0.8) \times (NO_X\text{+NMHC emission credits}).$$

(d) *Other restrictions.* Other sections of this part specify additional restrictions for using emission credits under certain special provisions.

§ 1039.745 What can happen if I do not comply with the provisions of this subpart?

(a) For each engine family participating in the ABT program, the certificate of conformity is conditional upon full compliance with the provisions of this subpart during and after the model year. You are responsible to establish to our satisfaction that you fully comply with applicable requirements. We may void the certificate of conformity for an engine family if you fail to comply with any provisions of this subpart.

(b) You may certify your engine family to an FEL above an applicable standard based on a projection that you will have enough emission credits to offset the deficit for the engine family. However, we may void the certificate of conformity if you cannot show in your final report that you have enough actual emission credits to offset a deficit for any pollutant in an engine family.

(c) We may void the certificate of conformity for an engine family if you fail to keep records, send reports, or give us information we request.

(d) You may ask for a hearing if we void your certificate under this section (see § 1039.820).

Subpart I—Definitions and Other Reference Information

§ 1039.801 What definitions apply to this part?

The following definitions apply to this part. The definitions apply to all subparts unless we note otherwise. All undefined terms have the meaning the Act gives to them. The definitions follow:

Act means the Clean Air Act, as amended, 42 U.S.C. 7401–7671q.

Adjustable parameter means any device, system, or element of design that someone can adjust (including those which are difficult to access) and that, if adjusted, may affect emissions or engine performance during emission testing or normal in-use operation. This includes, but is not limited to, parameters related to injection timing and fueling rate. You may ask us to exclude a parameter that is difficult to access if it cannot be adjusted to affect emissions without significantly degrading engine performance, or if you otherwise show us that it will not be adjusted in a way that affects emissions during in-use operation.

Aftertreatment means relating to a catalytic converter, particulate filter, or any other system, component, or technology mounted downstream of the exhaust valve (or exhaust port) whose design function is to reduce emissions in the engine exhaust before it is exhausted to the environment. Exhaust-gas recirculation (EGR) is not aftertreatment.

Aircraft means any vehicle capable of sustained air travel above treetop heights.

Auxiliary emission-control device means any element of design that senses temperature, motive speed, engine RPM, transmission gear, or any other parameter for the purpose of activating, modulating, delaying, or deactivating the operation of any part of the emission-control system.

Brake power means the usable power output of the engine, not including power required to fuel, lubricate, heat, or cool the engine or to operate aftertreatment devices.

Calibration means the set of specifications and tolerances specific to a particular design, version, or application of a component or assembly capable of functionally describing its operation over its working range.

Certification means obtaining a certificate of conformity for an engine family that complies with the emission standards and requirements in this part.

Certified emission level means the highest deteriorated emission level in an engine family for a given pollutant from either transient or steady-state testing.

Compression-ignition means relating to a type of reciprocating, internal-combustion engine that is not a spark-ignition engine.

Constant-speed engine means an engine whose certification is limited to constant-speed operation. Engines whose constant-speed governor function is removed or disabled are no longer constant-speed engines.

Constant-speed operation means engine operation with a governor that controls engine speed to a reference speed. There are two kinds of constant-speed governors. An isochronous governor changes reference speed temporarily during a load change, then returns it to the original reference speed after the engine stabilizes. Isochronous governors typically allow speed changes up to 1.0 percent. A speed-droop governor has a fixed reference speed at zero load and allows the reference speed to decrease as load increases. With speed-droop governors, speed typically decreases 3 to 10 percent below the reference speed at zero load, such that the minimum reference speed occurs near the engine's point of maximum power.

Crankcase emissions means airborne substances emitted to the atmosphere from any part of the engine crankcase's ventilation or lubrication systems. The crankcase is the housing for the crankshaft and other related internal parts.

Critical emission-related component means any of the following components:

(1) Electronic control units, aftertreatment devices, fuel-metering components, EGR-system components, crankcase-ventilation valves, all components related to charge-air compression and cooling, and all sensors and actuators associated with any of these components.

(2) Any other component whose primary purpose is to reduce emissions.

Designated Compliance Officer means the Manager, Engine Programs Group (6405–J), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460.

Designated Enforcement Officer means the Director, Air Enforcement Division (2242A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW.,Washington, DC 20460.

Deteriorated emission level means the emission level that results from applying the appropriate deterioration factor to the official emission result of the emission-data engine.

Deterioration factor means the relationship between emissions at the end of useful life and emissions at the low-hour test point, expressed in one of the following ways:

(1) For multiplicative deterioration factors, the ratio of emissions at the end of useful life to emissions at the low-hour test point.

(2) For additive deterioration factors, the difference between emissions at the end of useful life and emissions at the low-hour test point.

Discrete-mode means relating to the discrete-mode type of steady-state test described in § 1039.505.

Emission-control system means any device, system, or element of design that controls or reduces the regulated emissions from an engine.

Emission-data engine means an engine that is tested for certification. This includes engines tested to establish deterioration factors.

Emission-related maintenance means maintenance that substantially affects emissions or is likely to substantially affect emission deterioration.

Engine configuration means a unique combination of engine hardware and calibration within an engine family. Engines within a single engine configuration differ only with respect to normal production variability.

Engine family has the meaning given in § 1039.230.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Engine used in a locomotive means either an engine placed in the locomotive to move other equipment, freight, or passenger traffic; or an engine mounted on the locomotive to provide auxiliary power.

Equipment manufacturer means a manufacturer of nonroad equipment. All nonroad equipment manufacturing entities under the control of the same person are considered to be a single nonroad equipment manufacturer.

(Note: In § 1039.626, the term "equipment manufacturer" has a narrower meaning, which applies only to that section.)

Excluded means relating to an engine that either:

(1) Has been determined not to be a nonroad engine, as specified in 40 CFR 1068.30; or

(2) Is a nonroad engine that, according to § 1039.5, is not subject to this part 1039.

Exempted means relating to an engine that is not required to meet otherwise applicable standards. Exempted engines must conform to regulatory conditions specified for an exemption in this part 1039 or in 40 CFR part 1068. Exempted engines are deemed to be "subject to" the standards of this part, even though they are not required to comply with the otherwise applicable requirements. Engines exempted with respect to a certain tier of standards may be required to comply with an earlier tier of standards as a condition of the exemption; for example, engines exempted with respect to Tier 4 standards may be required to comply with Tier 3 standards.

Exhaust-gas recirculation means a technology that reduces emissions by routing exhaust gases that had been exhausted from the combustion chamber(s) back into the engine to be mixed with incoming air before or during combustion. The use of valve timing to increase the amount of residual exhaust gas in the combustion chamber(s) that is mixed with incoming air before or during combustion is not considered exhaust-gas recirculation for the purposes of this part.

Family emission limit (FEL) means an emission level declared by the manufacturer to serve in place of an otherwise applicable emission standard under the ABT program in subpart H of this part. The family emission limit must be expressed to the same number of decimal places as the emission standard it replaces. The family emission limit serves as the emission standard for the engine family with respect to all required testing.

Fuel system means all components involved in transporting, metering, and mixing the fuel from the fuel tank to the combustion chamber(s), including the fuel tank, fuel tank cap, fuel pump, fuel filters, fuel lines, carburetor or fuel-injection components, and all fuel-system vents.

Fuel type means a general category of fuels such as diesel fuel or natural gas. There can be multiple grades within a single fuel type, such as high-sulfur or low-sulfur diesel fuel.

Generator-set engine means an engine used primarily to operate an electrical generator or alternator to produce electric power for other applications.

Good engineering judgment means judgments made consistent with generally accepted scientific and engineering principles and all available relevant information. See 40 CFR 1068.5 for the administrative process we use to evaluate good engineering judgment.

High-sulfur diesel fuel means one of the following:

(1) For in-use fuels, *high-sulfur diesel fuel* means a diesel fuel with a maximum sulfur concentration greater than 500 parts per million.

(2) For testing, *high-sulfur diesel fuel* has the meaning we give in 40 CFR part 1065.

Hydrocarbon (HC) means the hydrocarbon group on which the emission standards are based for each fuel type. For alcohol-fueled engines, HC means total hydrocarbon equivalent (THCE). For all other engines, HC means nonmethane hydrocarbon (NMHC).

Identification number means a unique specification (for example, a model number/serial number combination) that allows someone to distinguish a particular engine from other similar engines.

Intermediate test speed has the meaning we give in 40 CFR 1065.515.

Low-hour means relating to an engine with stabilized emissions and represents the undeteriorated emission level. This would generally involve less than 300 hours of operation.

Low-sulfur diesel fuel means one of the following:

(1) For in-use fuels, *low-sulfur diesel* fuel means a diesel fuel with a maximum sulfur concentration of 500 parts per million.

(2) For testing, *low-sulfur diesel fuel* has the meaning we give in 40 CFR part 1065.

Manufacture means the physical and engineering process of designing, constructing, and assembling a nonroad engine or a piece of nonroad equipment.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures an engine, vehicle, or piece of equipment for sale in the United States or otherwise introduces a new nonroad engine into commerce in the United States. This includes importers who import engines, equipment, or vehicles for resale. (Note: In § 1039.626, the term "equipment manufacturer" has a narrower meaning, which applies only to that section.)

Marine engine means a nonroad engine that someone installs or intends to install on a marine vessel. This does not include portable auxiliary engines for which the fueling, cooling and exhaust systems are not integral parts of the vessel. There are two kinds of marine engines:

(1) *Propulsion marine engine* means a marine engine that moves a vessel through the water or directs the vessel's movement.

(2) *Auxiliary marine engine* means a marine engine not used for propulsion.

Marine vessel has the meaning given in 1 U.S.C. 3, which generally includes all nonroad equipment used as a means of transportation on water.

Maximum engine power has the meaning given in § 1039.140. Note that § 1039.230 generally disallows grouping engines from different power categories in the same engine family.

Maximum test speed has the meaning we give in 40 CFR 1065.515.

Maximum test torque has the meaning we give in 40 CFR 1065.1001.

Model year means one of the following things:

(1) For freshly manufactured equipment and engines (see definition of "new nonroad engine," paragraph (1)), model year means one of the following:

(i) Calendar year.

(ii) Your annual new model production period if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a nonroad engine after being placed into service as a motor-vehicle engine or a stationary engine, model year means the calendar year in which the engine was originally produced (see definition of "new nonroad engine," paragraph (2)).

(3) For a nonroad engine excluded under § 1039.5 that is later converted to operate in an application that is not excluded, model year means the calendar year in which the engine was originally produced (see definition of "new nonroad engine," paragraph (3)).

(4) For engines that are not freshly manufactured but are installed in new nonroad equipment, model year means the calendar year in which the engine is installed in the new nonroad equipment (see definition of "new nonroad engine," paragraph (4)).

(5) For imported engines:

(i) For imported engines described in paragraph (5)(i) of the definition of "new nonroad engine," *model year* has the meaning given in paragraphs (1) through (4) of this definition.

(ii) For imported engines described in paragraph (5)(ii) of the definition of "new nonroad engine," *model year* has the meaning given in 40 CFR 89.602 for independent commercial importers.

Motor vehicle has the meaning we give in 40 CFR 85.1703(a). In general, *motor vehicle* means any vehicle that EPA deems to be capable of safe and practical use on streets or highways.

New nonroad engine means any of the following things:

(1) A freshly manufactured nonroad engine for which the ultimate purchaser has never received the equitable or legal title. This kind of engine might commonly be thought of as "brand new." In the case of this paragraph (1), the engine becomes new when it is fully assembled for the first time. The engine is no longer new when the ultimate purchaser receives the title or the product is placed into service, whichever comes first.

(2) An engine originally manufactured as a motor-vehicle engine or a stationary engine that is later intended to be used in a piece of nonroad equipment. In this case, the engine is no longer a motor-vehicle or stationary engine and becomes a "new nonroad engine". The engine is no longer new when it is placed into nonroad service.

(3) A nonroad engine that has been previously placed into service in an application we exclude under § 1039.5, where that engine is installed in a piece of equipment that is covered by this part 1039. The engine is no longer new when it is placed into nonroad service covered by this part 1039. For example, this would apply to a marine diesel engine that is no longer used in a marine vessel.

(4) An engine not covered by paragraphs (1) through (3) of this definition that is intended to be installed in new nonroad equipment. The engine is no longer new when the ultimate purchaser receives a title for the equipment or the product is placed into service, whichever comes first. This generally includes installation of used engines in new equipment.

(5) An imported nonroad engine, subject to the following provisions:

(i) An imported nonroad engine covered by a certificate of conformity issued under this part that meets the criteria of one or more of paragraphs (1) through (4) of this definition, where the original engine manufacturer holds the certificate, is new as defined by those applicable paragraphs.

(ii) An imported nonroad engine covered by a certificate of conformity issued under this part, where someone other than the original engine manufacturer holds the certificate (such as when the engine is modified after its initial assembly), becomes new when it is imported. It is no longer new when the ultimate purchaser receives a title for the engine or it is placed into service, whichever comes first.

(iii) An imported nonroad engine that is not covered by a certificate of conformity issued under this part at the time of importation is new, but only if it was produced on or after the dates shown in the following table. This addresses uncertified engines and equipment initially placed into service that someone seeks to import into the United States. Importation of this kind of new nonroad engine (or equipment containing such an engine) is generally prohibited by 40 CFR part 1068.

APPLICABILITY OF EMISSION STANDARDS FOR NONROAD DIESEL ENGINES

Maximum engine power	Initial date of emission standards
kW < 19	January 1, 2000.
19 ≤ kW < 37	January 1, 1999.
37 ≤ kW < 75	January 1, 1998.
75 ≤ kW < 130	January 1, 1997.
130 ≤ kW ≤ 560	January 1, 1996.
kW > 560	January 1, 2000.

New nonroad equipment means either of the following things:

(1) A nonroad piece of equipment for which the ultimate purchaser has never received the equitable or legal title. The product is no longer new when the ultimate purchaser receives this title or the product is placed into service, whichever comes first.

(2) An imported nonroad piece of equipment with an engine not covered by a certificate of conformity issued under this part at the time of importation and manufactured after the requirements of this part start to apply (see § 1039.1).

Noncommercial fuel means a combustible product that is not marketed as a commercial fuel, but is used as a fuel for nonroad engines. For example, this includes methane that is produced and released from landfills or oil wells, or similar unprocessed fuels that are not intended to meet any otherwise applicable fuel specifications. See § 1039.615 for provisions related to engines designed to burn noncommercial fuels.

Noncompliant engine means an engine that was originally covered by a certificate of conformity, but is not in the certified configuration or otherwise does not comply with the conditions of the certificate.

Nonconforming engine means an engine not covered by a certificate of conformity that would otherwise be subject to emission standards.

Nonmethane hydrocarbon means the difference between the emitted mass of total hydrocarbons and the emitted mass of methane.

Nonroad means relating to nonroad engines or equipment that includes nonroad engines.

Nonroad engine has the meaning we give in 40 CFR 1068.30. In general this means all internal-combustion engines except motor vehicle engines, stationary engines, engines used solely for competition, or engines used in aircraft. This part does not apply to all nonroad engines (see § 1039.5).

Nonroad equipment means a piece of equipment that is powered by one or more nonroad engines.

Official emission result means the measured emission rate for an emission-data engine on a given duty cycle before the application of any deterioration factor, but after the applicability of regeneration adjustment factors.

Opacity means the fraction of a beam of light, expressed in percent, which fails to penetrate a plume of smoke, as measured by the procedure specified in § 1039.501.

Oxides of nitrogen has the meaning we give in 40 CFR part 1065.

Particulate trap means a filtering device that is designed to physically trap all particulate matter above a certain size.

Piece of equipment means any vehicle, vessel, or other type of equipment using engines to which this part applies.

Placed into service means put into initial use for its intended purpose.

Point of first retail sale means the location at which the initial retail sale occurs. This generally means an equipment dealership, but may also include an engine seller or distributor in cases where loose engines are sold to the general public for uses such as replacement engines.

Power category means a specific range of maximum engine power that defines the applicability of standards. For example, references to the 56–130 kW power category and 56 ≤ kW < 130 include all engines with maximum engine power at or above 56 kW but below 130 kW. Also references to 56–560 kW power categories or 56 ≤ kW ≤ 560 include all engines with maximum engine power at or above 56 kW but at or below 560 kW, even though these engines span multiple power categories. Note that in some cases, FEL caps are based on a subset of a power category. The power categories are defined as follows:

(1) Engines with maximum power below 19 kW.

(2) Engines with maximum power at or above 19 kW but below 56 kW.

(3) Engines with maximum power at or above 56 kW but below 130 kW.

(4) Engines with maximum power at or above 130 kW but at or below 560 kW.

(5) Engines with maximum power above 560 kW.

Ramped-modal means relating to the ramped-modal type of steady-state test described in § 1039.505.

Rated speed means the maximum full-load governed speed for governed engines and the speed of maximum power for ungoverned engines.

Revoke means to terminate the certificate or an exemption for an engine family. If we revoke a certificate or exemption, you must apply for a new certificate or exemption before continuing to introduce the affected engines into commerce. This does not apply to engines you no longer possess.

Round means to round numbers according to NIST Special Publication 811(incorporated by reference in § 1039.810), unless otherwise specified.

Scheduled maintenance means adjusting, repairing, removing, disassembling, cleaning, or replacing components or systems periodically to keep a part or system from failing, malfunctioning, or wearing prematurely. It also may mean actions you expect are necessary to correct an overt indication of failure or malfunction for which periodic maintenance is not appropriate.

Small-volume engine manufacturer means a small business engine manufacturer that had engine families certified to meet the requirements of 40 CFR part 89 before 2003 (40 CFR part 89, revised as of July 1, 2002), had annual U.S.-directed production of no more than 2,500 units in 2002 and all earlier calendar years, and has 1000 or fewer employees. For manufacturers owned by a parent company, the production limit applies to the production of the parent company and all its subsidiaries and the employee limit applies to the total number of employees of the parent company and all its subsidiaries.

Spark-ignition means relating to a gasoline-fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark-ignition engines usually use a throttle to regulate intake air flow to control power during normal operation.

Steady-state means relating to emission tests in which engine speed and load are held at a finite set of essentially constant values. Steady-state tests are either discrete-mode tests or ramped-modal tests.

Sulfur-sensitive technology means an emission-control technology that experiences a significant drop in emission-control performance or emission-system durability when an engine is operated on low-sulfur fuel (*i.e.*, fuel with a sulfur concentration of 300 to 500 ppm) as compared to when it is operated on ultra low-sulfur fuel (*i.e.*, fuel with a sulfur concentration less than 15 ppm). Exhaust-gas recirculation is not a sulfur-sensitive technology.

Suspend means to temporarily discontinue the certificate or an exemption for an engine family. If we suspend a certificate, you may not introduce into commerce engines from that engine family unless we reinstate the certificate or approve a new one. If we suspend an exemption, you may not introduce into commerce engines that were previously covered by the exemption unless we reinstate the exemption.

Test engine means an engine in a test sample.

Test sample means the collection of engines selected from the population of an engine family for emission testing. This may include testing for certification, production-line testing, or in-use testing.

Tier 1 means relating to the Tier 1 emission standards, as shown in 40 CFR 89.112.

Tier 2 means relating to the Tier 2 emission standards, as shown in 40 CFR 89.112.

Tier 3 means relating to the Tier 3 emission standards, as shown in 40 CFR 89.112.

Tier 4 means relating to the Tier 4 emission standards, as shown in § 1039.101 and § 1039.102. This includes the emission standards that are shown in § 1039.101 and § 1039.102 that are unchanged from Tier 2 or Tier 3 emission standards.

Total hydrocarbon means the combined mass of organic compounds measured by the specified procedure for measuring total hydrocarbon, expressed as a hydrocarbon with a hydrogen-to-carbon mass ratio of 1.85:1.

Total hydrocarbon equivalent means the sum of the carbon mass contributions of non-oxygenated hydrocarbons, alcohols and aldehydes, or other organic compounds that are measured separately as contained in a gas sample, expressed as exhaust hydrocarbon from petroleum-fueled engines. The hydrogen-to-carbon ratio of the equivalent hydrocarbon is 1.85:1.

Ultimate purchaser means, with respect to any new nonroad equipment or new nonroad engine, the first person who in good faith purchases such new nonroad equipment or new nonroad engine for purposes other than resale.

Ultra low-sulfur diesel fuel means one of the following:

(1) For in-use fuels, *ultra low-sulfur diesel fuel* means a diesel fuel with a maximum sulfur concentration of 15 parts per million.

(2) For testing, *ultra low-sulfur diesel fuel* has the meaning we give in 40 CFR part 1065.

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, Guam, American Samoa, and the U.S. Virgin Islands.

Upcoming model year means for an engine family the model year after the one currently in production.

U.S.-directed production volume means the number of engine units, subject to the requirements of this part, produced by a manufacturer for which the manufacturer has a reasonable assurance that sale was or will be made to ultimate purchasers in the United States.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. It is the period during which a new nonroad engine is required to comply with all applicable emission standards. *See* § 1039.101(g).

Variable-speed engine means an engine that is not a constant-speed engine.

Void means to invalidate a certificate or an exemption *ab initio*. If we void a certificate, all the engines introduced into commerce under that engine family for that model year are considered noncompliant, and you are liable for each engine introduced into commerce under the certificate and may face civil or criminal penalties or both. This applies equally to all engines in the engine family, including engines introduced into commerce before we voided the certificate. If we void an exemption, all the engines introduced into commerce under that exemption are considered uncertified (or nonconforming), and you are liable for each engine introduced into commerce under the exemption and may face civil or criminal penalties or both. You may not introduce into commerce any additional engines using the voided exemption.

Volatile liquid fuel means any fuel other than diesel or biodiesel that is a liquid at atmospheric pressure and has a Reid Vapor Pressure higher than 2.0 pounds per square inch.

We (us, our) means the Administrator of the Environmental Protection Agency and any authorized representatives.

§ 1039.805 What symbols, acronyms, and abbreviations does this part use?

The following symbols, acronyms, and abbreviations apply to this part:

CFR Code of Federal Regulations.
CO carbon monoxide.
CO2 carbon dioxide.
EPA Environmental Protection Agency.
FEL Family Emission Limit.
g/kW-hr grams per kilowatt-hour.
HC hydrocarbon.
kW kilowatts.
NIST National Institute of Standards and Technology.
NMHC nonmethane hydrocarbons.
NO_X oxides of nitrogen (NO and NO_2).
NTE not-to-exceed
PM particulate matter.
rpm revolutions per minute.
SAE Society of Automotive Engineers.
SEA Selective enforcement audit.
THC total hydrocarbon.
THCE total hydrocarbon equivalent.
TRU transportation refrigeration unit.
U.S.C. United States Code.

§ 1039.810 What materials does this part reference?

Documents listed in this section have been incorporated by reference into this part. The Director of the Federal Register approved the incorporation by reference as prescribed in 5 U.S.C. 552(a) and 1 CFR part 51. Anyone may inspect copies at the U.S. EPA, Air and Radiation Docket and Information Center, 1301 Constitution Ave., NW., Room B102, EPA West Building, Washington, DC 20460 or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(a) *NIST material.* Table 1 of this section lists material from the National Institute of Standards and Technology that we have incorporated by reference. The first column lists the number and name of the material. The second column lists the sections of this part where we reference it. Anyone may purchase copies of these materials from the Government Printing Office, Washington, DC 20402 or download them from the Internet at *http://physics.nist.gov/Pubs/SP811/.* Table 1 follows:

TABLE 1 OF § 1039.810.—NIST MATERIALS

Document number and name	Part 1039 reference
NIST Special Publication 811, Guide for the Use of the International System of Units (SI), 1995 Edition	1039.801

(b) *SAE material.* Table 2 of this section lists material from the Society of Automotive Engineering that we have incorporated by reference. The first column lists the number and name of the material. The second column lists the sections of this part where we reference it. Anyone may purchase copies of these materials from the Society of Automotive Engineers, 400 Commonwealth Drive, Warrendale, PA 15096. Table 2 follows:

TABLE 2 OF § 1039.810.—SAE MATERIALS

Document number and name	Part 1039 reference
SAE J1930, Electrical/Electronic Systems Diagnostic Terms, Definitions, Abbreviations, and Acronyms, revised May 1998	1039.135

§ 1039.815 What provisions apply to confidential information?

(a) Clearly show what you consider confidential by marking, circling, bracketing, stamping, or some other method.

(b) We will store your confidential information as described in 40 CFR part 2. Also, we will disclose it only as specified in 40 CFR part 2. This applies both to any information you send us and to any information we collect from inspections, audits, or other site visits.

(c) If you send us a second copy without the confidential information, we will assume it contains nothing confidential whenever we need to release information from it.

(d) If you send us information without claiming it is confidential, we may make it available to the public without further notice to you, as described in 40 CFR 2.204.

§ 1039.820 How do I request a hearing?

(a) You may request a hearing under certain circumstances, as described elsewhere in this part. To do this, you must file a written request, including a description of your objection and any supporting data, within 30 days after we make a decision.

(b) For a hearing you request under the provisions of this part, we will approve your request if we find that your request raises a substantial factual issue.

(c) If we agree to hold a hearing, we will use the procedures specified in 40 CFR part 1068, subpart G.

Appendix I to Part 1039—[Reserved]

Appendix II to Part 1039—Steady-State Duty Cycles for Constant-Speed Engines

(a) The following duty cycle applies for discrete-mode testing of constant-speed engines:

D2 mode number	Engine speed [1]	Torque (percent) [2]	Weighting factors
1	Maximum test speed	100	0.05
2	Maximum test speed	75	0.25
3	Maximum test speed	50	0.30
4	Maximum test speed	25	0.30
5	Maximum test speed	10	0.10

[1] Maximum test speed is defined in 40 CFR part 1065.
[2] Except as noted in § 1039.505, the percent torque is relative to maximum test torque.

(b) The following duty cycle applies for ramped-modal testing of constant-speed engines:

RMC mode	Time in mode (seconds)	Engine speed	Torque (percent)[1,2]
1a Steady-state	53	Engine Governed	100.
1b Transition	20	Engine Governed	Linear transition.
2a Steady-state	101	Engine Governed	10.
2b Transition	20	Engine Governed	Linear transition.
3a Steady-state	277	Engine Governed	75.
3b Transition	20	Engine Governed	Linear transition.
4a Steady-state	339	Engine Governed	25.
4b Transition	20	Engine Governed	Linear transition.
5 Steady-state	350	Engine Governed	50.

[1] The percent torque is relative to maximum test torque.
[2] Advance from one mode to the next within a 20-second transition phase. During the transition phase, command a linear progression from the torque setting of the current mode to the torque setting of the next mode.

Appendix III to Part 1039—Steady-State Duty Cycles for Variable-Speed Engines With Maximum Power Below 19 kW

(a) The following duty cycle applies for discrete-mode testing of variable-speed engines with maximum power below 19 kW:

G2 mode number	Engine speed[1]	Observed torque (percent)[2]	Weighting factors
1	Maximum test speed	100	0.09
2	Maximum test speed	75	0.20
3	Maximum test speed	50	0.29
4	Maximum test speed	25	0.30
5	Maximum test speed	10	0.07
6	Idle	0	0.05

[1] Speed terms are defined in 40 CFR part 1065.
[2] The percent torque is relative to the maximum torque at the commanded test speed.

(b) The following duty cycle applies for ramped-modal testing of variable-speed engines with maximum power below 19 kW:

RMC mode	Time in mode (seconds)	Engine speed[1,3]	Torque (percent)[2,3]
1a Steady-state	41	Warm Idle	0.
1b Transition	20	Linear transition	Linear transition.
2a Steady-state	135	Maximum Test Speed	100.
2b Transition	20	Maximum Test Speed	Linear transition.
3a Steady-state	112	Maximum Test Speed	10.
3b Transition	20	Maximum Test Speed	Linear transition.
4a Steady-state	337	Maximum Test Speed	75.
4b Transition	20	Maximum Test Speed	Linear transition.
5a Steady-state	518	Maximum Test Speed	25.
5b Transition	20	Maximum Test Speed	Linear transition.
6a Steady-state	494	Maximum Test Speed	50.
6b Transition	20	Linear transition	Linear transition.
7 Steady-state	43	Warm Idle	0.

[1] Speed terms are defined in 40 CFR part 1065.
[2] The percent torque is relative to the maximum torque at the commanded engine speed.
[3] Advance from one mode to the next within a 20-second transition phase. During the transition phase, command a linear progression from the torque setting of the current mode to the torque setting of the next mode, and simultaneously command a similar linear progression for engine speed if there is a change in speed setting.

Appendix IV to Part 1039—Steady-State Duty Cycles for Variable-Speed Engines With Maximum Power at or Above 19 kW

(a) The following duty cycle applies for discrete-mode testing of variable-speed engines with maximum power at or above 19 kW:

C1 mode number	Engine speed [1]	Observed torque (percent) [2]	Weighting factors
1	Maximum test speed	100	0.15
2	Maximum test speed	75	0.15
3	Maximum test speed	50	0.15
4	Maximum test speed	10	0.10
5	Intermediate test speed	100	0.10
6	Intermediate test speed	75	0.10
7	Intermediate test speed	50	0.10
8	Idle	0	0.15

[1] Speed terms are defined in 40 CFR part 1065.
[2] The percent torque is relative to the maximum torque at the commanded test speed.

(b) The following duty cycle applies for ramped-modal testing of variable-speed engines with maximum power at or above 19 kW:

RMC Mode	Time in mode (seconds)	Engine speed [1,3]	Torque (percent) [2,3]
1a Steady-state	126	Warm Idle	0.
1b Transition	20	Linear Transition [2]	Linear Transition.
2a Steady-state	159	Intermediate Speed	100.
2b Transition	20	Intermediate Speed	Linear Transition.
3a Steady-state	160	Intermediate Speed	50.
3b Transition	20	Intermediate Speed	Linear Transition.
4a Steady-state	162	Intermediate Speed	75.
4b Transition	20	Linear Transition	Linear Transition.
5a Steady-state	246	Maximum Test Speed	100.
5b Transition	20	Maximum Test Speed	Linear Transition.
6a Steady-state	164	Maximum Test Speed	10.
6b Transition	20	Maximum Test Speed	Linear Transition.
7a Steady-state	248	Maximum Test Speed	75.
7b Transition	20	Maximum Test Speed	Linear Transition.
8a Steady-state	247	Maximum Test Speed	50.
8b Transition	20	Linear Transition	Linear Transition.
9 Steady-state	128	Warm Idle	0.

[1] Speed terms are defined in 40 CFR part 1065.
[2] The percent torque is relative to the maximum torque at the commanded engine speed.
[3] Advance from one mode to the next within a 20-second transition phase. During the transition phase, command a linear progression from the torque setting of the current mode to the torque setting of the next mode, and simultaneously command a similar linear progression for engine speed if there is a change in speed setting.

Appendix V to Part 1039 [Reserved]

Appendix VI to Part 1039—Nonroad Compression-ignition Composite Transient Cycle

Time(s)	Normalized speed (percent)	Normalized torque (percent)
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	0	0
7	0	0
8	0	0
9	0	0
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
18	0	0
19	0	0
20	0	0
21	0	0
22	0	0
23	0	0
24	1	3
25	1	3
26	1	3
27	1	3
28	1	3
29	1	3
30	1	6
31	1	6
32	2	1
33	4	13
34	7	18
35	9	21
36	17	20
37	33	42
38	57	46
39	44	33
40	31	0
41	22	27
42	33	43
43	80	49
44	105	47
45	98	70
46	104	36
47	104	65
48	96	71
49	101	62
50	102	51
51	102	50
52	102	46
53	102	41
54	102	31
55	89	2
56	82	0
57	47	1
58	23	1
59	1	3
60	1	8
61	1	3
62	1	5
63	1	6
64	1	4
65	1	4
66	0	6
67	1	4

Time(s)	Normalized speed (percent)	Normalized torque (percent)
68	9	21
69	25	56
70	64	26
71	60	31
72	63	20
73	62	24
74	64	8
75	58	44
76	65	10
77	65	12
78	68	23
79	69	30
80	71	30
81	74	15
82	71	23
83	73	20
84	73	21
85	73	19
86	70	33
87	70	34
88	65	47
89	66	47
90	64	53
91	65	45
92	66	38
93	67	49
94	69	39
95	69	39
96	66	42
97	71	29
98	75	29
99	72	23
100	74	22
101	75	24
102	73	30
103	74	24
104	77	6
105	76	12
106	74	39
107	72	30
108	75	22
109	78	64
110	102	34
111	103	28
112	103	28
113	103	19
114	103	32
115	104	25
116	103	38
117	103	39
118	103	34
119	102	44
120	103	38
121	102	43
122	103	34
123	102	41
124	103	44
125	103	37
126	103	27
127	104	13
128	104	30
129	104	19
130	103	28
131	104	40
132	104	32
133	101	63
134	102	54
135	102	52
136	102	51
137	103	40
138	104	34
139	102	36
140	104	44
141	103	44
142	104	33
143	102	27
144	103	26
145	79	53
146	51	37
147	24	23
148	13	33
149	19	55
150	45	30
151	34	7
152	14	4
153	8	16
154	15	6
155	39	47
156	39	4
157	35	26
158	27	38
159	43	40
160	14	23
161	10	10
162	15	33
163	35	72
164	60	39
165	55	31
166	47	30
167	16	7
168	0	6
169	0	8
170	0	8
171	0	2
172	2	17
173	10	28
174	28	31
175	33	30
176	36	0
177	19	10
178	1	18
179	0	16
180	1	3
181	1	4
182	1	5
183	1	6
184	1	5
185	1	3
186	1	4
187	1	4
188	1	6
189	8	18
190	20	51
191	49	19
192	41	13
193	31	16
194	28	21
195	21	17
196	31	21
197	21	8
198	0	14
199	0	12
200	3	8
201	3	22
202	12	20
203	14	20
204	16	17
205	20	18
206	27	34
207	32	33
208	41	31
209	43	31
210	37	33
211	26	18
212	18	29
213	14	51
214	13	11
215	12	9
216	15	33
217	20	25
218	25	17
219	31	29
220	36	66
221	66	40
222	50	13
223	16	24
224	26	50
225	64	23
226	81	20
227	83	11
228	79	23
229	76	31
230	68	24
231	59	33
232	59	3
233	25	7
234	21	10
235	20	19
236	4	10
237	5	7
238	4	5
239	4	6
240	4	6
241	4	5
242	7	5
243	16	28
244	28	25
245	52	53
246	50	8
247	26	40
248	48	29
249	54	39
250	60	42
251	48	18
252	54	51
253	88	90
254	103	84
255	103	85
256	102	84
257	58	66
258	64	97
259	56	80
260	51	67
261	52	96
262	63	62
263	71	6
264	33	16
265	47	45
266	43	56
267	42	27
268	42	64
269	75	74
270	68	96
271	86	61
272	66	0
273	37	0
274	45	37
275	68	96
276	80	97
277	92	96
278	90	97
279	82	96
280	94	81
281	90	85
282	96	65
283	70	96

Time(s)	Normalized speed (percent)	Normalized torque (percent)
284	55	95
285	70	96
286	79	96
287	81	71
288	71	60
289	92	65
290	82	63
291	61	47
292	52	37
293	24	0
294	20	7
295	39	48
296	39	54
297	63	58
298	53	31
299	51	24
300	48	40
301	39	0
302	35	18
303	36	16
304	29	17
305	28	21
306	31	15
307	31	10
308	43	19
309	49	63
310	78	61
311	78	46
312	66	65
313	78	97
314	84	63
315	57	26
316	36	22
317	20	34
318	19	8
319	9	10
320	5	5
321	7	11
322	15	15
323	12	9
324	13	27
325	15	28
326	16	28
327	16	31
328	15	20
329	17	0
330	20	34
331	21	25
332	20	0
333	23	25
334	30	58
335	63	96
336	83	60
337	61	0
338	26	0
339	29	44
340	68	97
341	80	97
342	88	97
343	99	88
344	102	86
345	100	82
346	74	79
347	57	79
348	76	97
349	84	97
350	86	97
351	81	98
352	83	83
353	65	96
354	93	72
355	63	60
356	72	49
357	56	27
358	29	0
359	18	13
360	25	11
361	28	24
362	34	53
363	65	83
364	80	44
365	77	46
366	76	50
367	45	52
368	61	98
369	61	69
370	63	49
371	32	0
372	10	8
373	17	7
374	16	13
375	11	6
376	9	5
377	9	12
378	12	46
379	15	30
380	26	28
381	13	9
382	16	21
383	24	4
384	36	43
385	65	85
386	78	66
387	63	39
388	32	34
389	46	55
390	47	42
391	42	39
392	27	0
393	14	5
394	14	14
395	24	54
396	60	90
397	53	66
398	70	48
399	77	93
400	79	67
401	46	65
402	69	98
403	80	97
404	74	97
405	75	98
406	56	61
407	42	0
408	36	32
409	34	43
410	68	83
411	102	48
412	62	0
413	41	39
414	71	86
415	91	52
416	89	55
417	89	56
418	88	58
419	78	69
420	98	39
421	64	61
422	90	34
423	88	38
424	97	62
425	100	53
426	81	58
427	74	51
428	76	57
429	76	72
430	85	72
431	84	60
432	83	72
433	83	72
434	86	72
435	89	72
436	86	72
437	87	72
438	88	72
439	88	71
440	87	72
441	85	71
442	88	72
443	88	72
444	84	72
445	83	73
446	77	73
447	74	73
448	76	72
449	46	77
450	78	62
451	79	35
452	82	38
453	81	41
454	79	37
455	78	35
456	78	38
457	78	46
458	75	49
459	73	50
460	79	58
461	79	71
462	83	44
463	53	48
464	40	48
465	51	75
466	75	72
467	89	67
468	93	60
469	89	73
470	86	73
471	81	73
472	78	73
473	78	73
474	76	73
475	79	73
476	82	73
477	86	73
478	88	72
479	92	71
480	97	54
481	73	43
482	36	64
483	63	31
484	78	1
485	69	27
486	67	28
487	72	9
488	71	9
489	78	36
490	81	56
491	75	53
492	60	45
493	50	37
494	66	41
495	51	61
496	68	47
497	29	42
498	24	73
499	64	71

Time(s)	Normalized speed (percent)	Normalized torque (percent)	Time(s)	Normalized speed (percent)	Normalized torque (percent)	Time(s)	Normalized speed (percent)	Normalized torque (percent)
500	90	71	572	83	57	644	79	72
501	100	61	573	86	52	645	78	70
502	94	73	574	85	51	646	80	70
503	84	73	575	70	39	647	82	71
504	79	73	576	50	5	648	84	71
505	75	72	577	38	36	649	83	71
506	78	73	578	30	71	650	83	73
507	80	73	579	75	53	651	81	70
508	81	73	580	84	40	652	80	71
509	81	73	581	85	42	653	78	71
510	83	73	582	86	49	654	76	70
511	85	73	583	86	57	655	76	70
512	84	73	584	89	68	656	76	71
513	85	73	585	99	61	657	79	71
514	86	73	586	77	29	658	78	71
515	85	73	587	81	72	659	81	70
516	85	73	588	89	69	660	83	72
517	85	72	589	49	56	661	84	71
518	85	73	590	79	70	662	86	71
519	83	73	591	104	59	663	87	71
520	79	73	592	103	54	664	92	72
521	78	73	593	102	56	665	91	72
522	81	73	594	102	56	666	90	71
523	82	72	595	103	61	667	90	71
524	94	56	596	102	64	668	91	71
525	66	48	597	103	60	669	90	70
526	35	71	598	93	72	670	90	72
527	51	44	599	86	73	671	91	71
528	60	23	600	76	73	672	90	71
529	64	10	601	59	49	673	90	71
530	63	14	602	46	22	674	92	72
531	70	37	603	40	65	675	93	69
532	76	45	604	72	31	676	90	70
533	78	18	605	72	27	677	93	72
534	76	51	606	67	44	678	91	70
535	75	33	607	68	37	679	89	71
536	81	17	608	67	42	680	91	71
537	76	45	609	68	50	681	90	71
538	76	30	610	77	43	682	90	71
539	80	14	611	58	4	683	92	71
540	71	18	612	22	37	684	91	71
541	71	14	613	57	69	685	93	71
542	71	11	614	68	38	686	93	68
543	65	2	615	73	2	687	98	68
544	31	26	616	40	14	688	98	67
545	24	72	617	42	38	689	100	69
546	64	70	618	64	69	690	99	68
547	77	62	619	64	74	691	100	71
548	80	68	620	67	73	692	99	68
549	83	53	621	65	73	693	100	69
550	83	50	622	68	73	694	102	72
551	83	50	623	65	49	695	101	69
552	85	43	624	81	0	696	100	69
553	86	45	625	37	25	697	102	71
554	89	35	626	24	69	698	102	71
555	82	61	627	68	71	699	102	69
556	87	50	628	70	71	700	102	71
557	85	55	629	76	70	701	102	68
558	89	49	630	71	72	702	100	69
559	87	70	631	73	69	703	102	70
560	91	39	632	76	70	704	102	68
561	72	3	633	77	72	705	102	70
562	43	25	634	77	72	706	102	72
563	30	60	635	77	72	707	102	68
564	40	45	636	77	70	708	102	69
565	37	32	637	76	71	709	100	68
566	37	32	638	76	71	710	102	71
567	43	70	639	77	71	711	101	64
568	70	54	640	77	71	712	102	69
569	77	47	641	78	70	713	102	69
570	79	66	642	77	70	714	101	69
571	85	53	643	77	71	715	102	64

Time(s)	Normalized speed (percent)	Normalized torque (percent)
716	102	69
717	102	68
718	102	70
719	102	69
720	102	70
721	102	70
722	102	62
723	104	38
724	104	15
725	102	24
726	102	45
727	102	47
728	104	40
729	101	52
730	103	32
731	102	50
732	103	30
733	103	44
734	102	40
735	103	43
736	103	41
737	102	46
738	103	39
739	102	41
740	103	41
741	102	38
742	103	39
743	102	46
744	104	46
745	103	49
746	102	45
747	103	42
748	103	46
749	103	38
750	102	48
751	103	35
752	102	48
753	103	49
754	102	48
755	102	46
756	103	47
757	102	49
758	102	42
759	102	52
760	102	57
761	102	55
762	102	61
763	102	61
764	102	58
765	103	58
766	102	59
767	102	54
768	102	63
769	102	61
770	103	55
771	102	60
772	102	72
773	103	56
774	102	55
775	102	67
776	103	56
777	84	42
778	48	7
779	48	6
780	48	6
781	48	7
782	48	6
783	48	7
784	67	21
785	105	59
786	105	96
787	105	74
788	105	66
789	105	62
790	105	66
791	89	41
792	52	5
793	48	5
794	48	7
795	48	5
796	48	6
797	48	4
798	52	6
799	51	5
800	51	6
801	51	6
802	52	5
803	52	5
804	57	44
805	98	90
806	105	94
807	105	100
808	105	98
809	105	95
810	105	96
811	105	92
812	104	97
813	100	85
814	94	74
815	87	62
816	81	50
817	81	46
818	80	39
819	80	32
820	81	28
821	80	26
822	80	23
823	80	23
824	80	20
825	81	19
826	80	18
827	81	17
828	80	20
829	81	24
830	81	21
831	80	26
832	80	24
833	80	23
834	80	22
835	81	21
836	81	24
837	81	24
838	81	22
839	81	22
840	81	21
841	81	31
842	81	27
843	80	26
844	80	26
845	81	25
846	80	21
847	81	20
848	83	21
849	83	15
850	83	12
851	83	9
852	83	8
853	83	7
854	83	6
855	83	6
856	83	6
857	83	6
858	83	6
859	76	5
860	49	8
861	51	7
862	51	20
863	78	52
864	80	38
865	81	33
866	83	29
867	83	22
868	83	16
869	83	12
870	83	9
871	83	8
872	83	7
873	83	6
874	83	6
875	83	6
876	83	6
877	83	6
878	59	4
879	50	5
880	51	5
881	51	5
882	51	5
883	50	5
884	50	5
885	50	5
886	50	5
887	50	5
888	51	5
889	51	5
890	51	5
891	63	50
892	81	34
893	81	25
894	81	29
895	81	23
896	80	24
897	81	24
898	81	28
899	81	27
900	81	22
901	81	19
902	81	17
903	81	17
904	81	17
905	81	15
906	80	15
907	80	28
908	81	22
909	81	24
910	81	19
911	81	21
912	81	20
913	83	26
914	80	63
915	80	59
916	83	100
917	81	73
918	83	53
919	80	76
920	81	61
921	80	50
922	81	37
923	82	49
924	83	37
925	83	25
926	83	17
927	83	13
928	83	10
929	83	8
930	83	7
931	83	7

Time(s)	Normalized speed (percent)	Normalized torque (percent)
932	83	6
933	83	6
934	83	6
935	71	5
936	49	24
937	69	64
938	81	50
939	81	43
940	81	42
941	81	31
942	81	30
943	81	35
944	81	28
945	81	27
946	80	27
947	81	31
948	81	41
949	81	41
950	81	37
951	81	43
952	81	34
953	81	31
954	81	26
955	81	23
956	81	27
957	81	38
958	81	40
959	81	39
960	81	27
961	81	33
962	80	28
963	81	34
964	83	72
965	81	49
966	81	51
967	80	55
968	81	48
969	81	36
970	81	39
971	81	38
972	80	41
973	81	30
974	81	23
975	81	19
976	81	25
977	81	29
978	83	47
979	81	90
980	81	75
981	80	60
982	81	48
983	81	41
984	81	30
985	80	24
986	81	20
987	81	21
988	81	29
989	81	29
990	81	27
991	81	23
992	81	25
993	81	26
994	81	22
995	81	20
996	81	17
997	81	23
998	83	65
999	81	54
1000	81	50
1001	81	41
1002	81	35
1003	81	37
1004	81	29
1005	81	28
1006	81	24
1007	81	19
1008	81	16
1009	80	16
1010	83	23
1011	83	17
1012	83	13
1013	83	27
1014	81	58
1015	81	60
1016	81	46
1017	80	41
1018	80	36
1019	81	26
1020	86	18
1021	82	35
1022	79	53
1023	82	30
1024	83	29
1025	83	32
1026	83	28
1027	76	60
1028	79	51
1029	86	26
1030	82	34
1031	84	25
1032	86	23
1033	85	22
1034	83	26
1035	83	25
1036	83	37
1037	84	14
1038	83	39
1039	76	70
1040	78	81
1041	75	71
1042	86	47
1043	83	35
1044	81	43
1045	81	41
1046	79	46
1047	80	44
1048	84	20
1049	79	31
1050	87	29
1051	82	49
1052	84	21
1053	82	56
1054	81	30
1055	85	21
1056	86	16
1057	79	52
1058	78	60
1059	74	55
1060	78	84
1061	80	54
1062	80	35
1063	82	24
1064	83	43
1065	79	49
1066	83	50
1067	86	12
1068	64	14
1069	24	14
1070	49	21
1071	77	48
1072	103	11
1073	98	48
1074	101	34
1075	99	39
1076	103	11
1077	103	19
1078	103	7
1079	103	13
1080	103	10
1081	102	13
1082	101	29
1083	102	25
1084	102	20
1085	96	60
1086	99	38
1087	102	24
1088	100	31
1089	100	28
1090	98	3
1091	102	26
1092	95	64
1093	102	23
1094	102	25
1095	98	42
1096	93	68
1097	101	25
1098	95	64
1099	101	35
1100	94	59
1101	97	37
1102	97	60
1103	93	98
1104	98	53
1105	103	13
1106	103	11
1107	103	11
1108	103	13
1109	103	10
1110	103	10
1111	103	11
1112	103	10
1113	103	10
1114	102	18
1115	102	31
1116	101	24
1117	102	19
1118	103	10
1119	102	12
1120	99	56
1121	96	59
1122	74	28
1123	66	62
1124	74	29
1125	64	74
1126	69	40
1127	76	2
1128	72	29
1129	66	65
1130	54	69
1131	69	56
1132	69	40
1133	73	54
1134	63	92
1135	61	67
1136	72	42
1137	78	2
1138	76	34
1139	67	80
1140	70	67
1141	53	70
1142	72	65
1143	60	57
1144	74	29
1145	69	31
1146	76	1
1147	74	22

Time(s)	Normalized speed (percent)	Normalized torque (percent)
1148	72	52
1149	62	96
1150	54	72
1151	72	28
1152	72	35
1153	64	68
1154	74	27
1155	76	14
1156	69	38
1157	66	59
1158	64	99
1159	51	86
1160	70	53
1161	72	36
1162	71	47
1163	70	42
1164	67	34
1165	74	2
1166	75	21
1167	74	15
1168	75	13
1169	76	10
1170	75	13
1171	75	10
1172	75	7
1173	75	13
1174	76	8
1175	76	7
1176	67	45
1177	75	13
1178	75	12
1179	73	21
1180	68	46
1181	74	8
1182	76	11
1183	76	14
1184	74	11
1185	74	18
1186	73	22
1187	74	20
1188	74	19
1189	70	22
1190	71	23
1191	73	19
1192	73	19
1193	72	20
1194	64	60
1195	70	39
1196	66	56
1197	68	64
1198	30	68
1199	70	38
1200	66	47
1201	76	14
1202	74	18
1203	69	46
1204	68	62
1205	68	62
1206	68	62
1207	68	62
1208	68	62
1209	68	62
1210	54	50
1211	41	37
1212	27	25
1213	14	12
1214	0	0
1215	0	0
1216	0	0
1217	0	0
1218	0	0
1219	0	0
1220	0	0
1221	0	0
1222	0	0
1223	0	0
1224	0	0
1225	0	0
1226	0	0
1227	0	0
1228	0	0
1229	0	0
1230	0	0
1231	0	0
1232	0	0
1233	0	0
1234	0	0
1235	0	0
1236	0	0
1237	0	0
1238	0	0

PART 1048—CONTROL OF EMISSIONS FROM NEW, LARGE NONROAD SPARK-IGNITION ENGINES

■ 89. The authority citation for part 1048 continues to read as follows:

Authority: 42 U.S.C. 7401–7671(q).

■ 90. Section 1048.125 is amended by revising paragraph (a) introductory text and paragraph (d) to read as follows:

§ 1048.125 What maintenance instructions must I give to buyers?

(a) *Critical emission-related maintenance.* Critical emission-related maintenance includes any adjustment, cleaning, repair, or replacement of critical emission-related components. This may also include additional emission-related maintenance that you determine is critical if we approve it in advance. You may schedule critical emission-related maintenance on these components if you meet the following conditions:

* * * * *

(d) *Noncritical emission-related maintenance.* You may schedule any amount of emission-related inspection or maintenance that is not covered by paragraph (a) of this section, as long as you state in the owners manual that these steps are not necessary to keep the emission-related warranty valid. If operators fail to do this maintenance, this does not allow you to disqualify those engines from in-use testing or deny a warranty claim. Do not take these inspection or maintenance steps during service accumulation on your emission-data engines.

* * * * *

■ 91. Section 1048.801 is amended by adding a definition for "Critical emission-related component" in alphabetical order to read as follows:

§ 1048.801 What definitions apply to this part?

* * * * *

Critical emission-related component means any of the following components:

(1) Electronic control units, aftertreatment devices, fuel-metering components, EGR-system components, crankcase-ventilation valves, all components related to charge-air compression and cooling, and all sensors and actuators associated with any of these components.

(2) Any other component whose primary purpose is to reduce emissions.

* * * * *

PART 1051—CONTROL OF EMISSIONS FROM RECREATIONAL ENGINES AND VEHICLES

■ 92. The authority citation for part 1051 continues to read as follows:

Authority: 42 U.S.C. 7401–7671(q).

■ 93. Section 1051.125 is amended by revising paragraph (a) introductory text and paragraph (d) to read as follows:

§ 1051.125 What maintenance instructions must I give to buyers?

(a) *Critical emission-related maintenance.* Critical emission-related maintenance includes any adjustment, cleaning, repair, or replacement of critical emission-related components. This may also include additional emission-related maintenance that you determine is critical if we approve it in advance. You may schedule critical emission-related maintenance on these components if you meet the following conditions:

* * * * *

(d) *Noncritical emission-related maintenance.* You may schedule any amount of emission-related inspection or maintenance that is not covered by paragraph (a) of this section, as long as you state in the owners manual that these steps are not necessary to keep the emission-related warranty valid. If operators fail to do this maintenance, this does not allow you to disqualify those engines from in-use testing or deny a warranty claim. Do not take these inspection or maintenance steps during service accumulation on your emission-data engines.

* * * * *

■ 94. Section 1051.801 is amended by adding a definition for "Critical emission-related component" in alphabetical order to read as follows:

§ 1051.801 What definitions apply to this part?

* * * * *

Critical emission-related component means any of the following components:

(1) Electronic control units, aftertreatment devices, fuel-metering components, EGR-system components, crankcase-ventilation valves, all components related to charge-air compression and cooling, and all sensors and actuators associated with any of these components.

(2) Any other component whose primary purpose is to reduce emissions.

* * * * *

PART 1065—TEST PROCEDURES AND EQUIPMENT

■ 95. The authority citation for part 1065 continues to read as follows:

Authority: 42 U.S.C. 7401–7671(q).

■ 96. Section 1065.1 is amended by revising paragraph (a) and removing and reserving paragraph (b)(6) to read as follows:

§ 1065.1 Applicability.

(a) This part describes the procedures that apply to testing that we require for the following engines or for equipment using the following engines:

(1) Large nonroad spark-ignition engines we regulate under 40 CFR part 1048.

(2) Vehicles that we regulate under 40 CFR part 1051 (*i.e.*, recreational SI vehicles) that are regulated based on engine testing. See 40 CFR part 1051 to determine which vehicles may be certified based on engine test data.

(3) Land-based nonroad compression-ignition engines we regulate under 40 CFR part 1039.

* * * * *

■ 97. Section 1065.10 is amended by revising paragraph (c)(3) to read as follows:

§ 1065.10 Other test procedures.

* * * * *

(c) * * *

(3) You may ask to use alternate procedures that produce measurements equivalent to those from the specified procedures. If you send us a written request showing your procedures are equivalent, and we agree that they are equivalent, we will allow you to use them. You may not use an alternate procedure until we approve them, either by: telling you directly that you may use this procedure; or issuing guidance to all manufacturers, which allows you to use the alternate procedure without additional approval. You may use the statistical procedures specified in 40 CFR 86.1306–07(d) to demonstrate equivalence, except that you test for equal variances by performing the F-test as follows, instead of the method specified in § 86.1306–07(d)(5)(iv)(C):

(i) Form the F ratio: $F = (Asd/Rsd)^2$.

Where:

Asd = the standard deviation of measurements with the alternate system.

Rsd = the standard deviation of measurements with the reference system.

(ii) F must be less than the critical t value, Fcrit, at a 90% confidence interval for "n-1" degrees of freedom.

(iii) The following table lists 90% confidence-interval Fcrit values for n–1 degrees of freedom. Note that nA represents the number of alternate system samples, while nR represents the number of reference system samples:

nR-1	nA-1	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6		3.055	3.014	2.983	2.958	2.937	2.92	2.905	2.892	2.881	2.871	2.863	2.855	2.848	2.842	2.836
7		2.827	2.785	2.752	2.725	2.703	2.684	2.668	2.654	2.643	2.632	2.623	2.615	2.607	2.601	2.595
8		2.668	2.624	2.589	2.561	2.538	2.519	2.502	2.488	2.475	2.464	2.455	2.446	2.438	2.431	2.425
9		2.551	2.505	2.469	2.440	2.416	2.396	2.379	2.364	2.351	2.340	2.329	2.320	2.312	2.305	2.298
10		2.461	2.414	2.377	2.347	2.323	2.302	2.284	2.269	2.255	2.244	2.233	2.224	2.215	2.208	2.201
11		2.389	2.342	2.304	2.274	2.248	2.227	2.209	2.193	2.179	2.167	2.156	2.147	2.138	2.13	2.123
12		2.331	2.283	2.245	2.214	2.188	2.166	2.147	2.131	2.117	2.105	2.094	2.084	2.075	2.067	2.06
13		2.283	2.234	2.195	2.164	2.138	2.116	2.097	2.080	2.066	2.053	2.042	2.032	2.023	2.014	2.007
14		2.243	2.193	2.154	2.122	2.095	2.073	2.054	2.037	2.022	2.010	1.998	1.988	1.978	1.97	1.962
15		2.208	2.158	2.119	2.086	2.059	2.037	2.017	2.000	1.985	1.972	1.961	1.950	1.941	1.932	1.924
16		2.178	2.128	2.088	2.055	2.028	2.005	1.985	1.968	1.953	1.940	1.928	1.917	1.908	1.899	1.891
17		2.152	2.102	2.061	2.028	2.001	1.978	1.958	1.940	1.925	1.912	1.900	1.889	1.879	1.87	1.862
18		2.130	2.079	2.038	2.005	1.977	1.954	1.933	1.916	1.900	1.887	1.875	1.864	1.854	1.845	1.837
19		2.109	2.058	2.017	1.984	1.956	1.932	1.912	1.894	1.878	1.865	1.852	1.841	1.831	1.822	1.814
20		2.091	2.040	1.999	1.965	1.937	1.913	1.892	1.875	1.859	1.845	1.833	1.821	1.811	1.802	1.794

* * * * *

■ 98. In § 1065.115, text is added to read as follows:

§ 1065.115 Exhaust gas sampling system; compression-ignition engines.

Use one of the following systems and procedures to measure emissions from compression-ignition engines:

(a) Full-flow dilution sampling as specified in 40 CFR 86.1310.

(b) Raw-gas sampling during steady-state tests as specified in 40 CFR 89.412 through 89.418.

(c) Partial-flow sampling for measuring gaseous emission constituents during steady-state tests as specified in 40 CFR 89.112(c).

■ 99. In § 1065.205, text is added to read as follows:

§ 1065.205 Test fuel specifications for distillate diesel fuel.

(a)(1) There are three grades of #2 diesel fuel specified for use as a test fuel. See the standard-setting part to determine which grade to use. If the standard-setting part does not specify which grade to use, use good engineering judgment to select the grade that represents the fuel on which the engines will operate in use. The three grades are specified as follows:

Item		ASTM test method No.[1]	Ultra low sulfur	Low sulfur	High sulfur
(i) Cetane Number		D 613	40–50	40–50	40–50
(ii) Cetane Index		D 976	40–50	40–50	40–50
(iii) Distillation range:					
(A) IBP	°C	D 86	171–204	171–204	171–204
(B) 10 pct. point	°C	D 86	204–238	204–238	204–238
(C) 50 pct. point	°C	D 86	243–282	243–282	243–282
(D) 90 pct. point	°C	D 86	293–332	293–332	293–332

Item		ASTM test method No.[1]	Ultra low sulfur	Low sulfur	High sulfur
(E) EP	°C	D 86	321–366	321–366	321–366
(iv) Gravity	°API	D 287	32–37	32–37	32–37
(v) Total sulfur	ppm	D 2622	7–15	300–500	2000–4000
(vi) Hydrocarbon composition:					
Aromatics, minimum. (Remainder shall be paraffins, naphthenes, and olefins).	pct	D 5186	10	10	10
(vii) Flashpoint, min	°C	D 93	54	54	54
(viii) Viscosity	centistokes	D 445	2.0–3.2	2.0–3.2	2.0–3.2

[1] All ASTM standards are incorporated by reference in § 1065.1010.

(2) [Reserved]

(b) There are no specifications for #1 diesel fuel. See § 1065.201(d) if your engines are designed to operate only on #1 diesel fuel.

■ 100. In § 1065.310, text is added to read as follows:

§ 1065.310 CVS calibration.

Use the procedures of 40 CFR 86.1319–90 to calibrate the CVS.

■ 101. Section 1065.405 is amended by revising paragraph (b) to read as follows:

§ 1065.405 Preparing and servicing a test engine.

* * * * *

(b) Run the test engine, with all emission-control systems operating, long enough to stabilize emission levels.

(1) For SI engines, if you accumulate 50 hours of operation, you may consider emission levels stable without measurement.

(2) For CI engines, if you accumulate 125 hours of operation, you may consider emission levels stable without measurement.

* * * * *

■ 102. Section 1065.530 is amended by revising paragraph (b)(3)(iii) and adding paragraphs (d) and (e) to read as follows:

§ 1065.530 Test cycle validation criteria.

* * * * *

(b) * * *

(3) * * *

(iii) For a valid test, make sure the feedback cycle's integrated brake kilowatt-hour is within 5 percent of the reference cycle's integrated brake kilowatt-hour. Also, ensure that the slope, intercept, standard error, and coefficient of determination meet the criteria in the following tables (you may delete individual points from the regression analyses, consistent with paragraph (e) of this section and good engineering judgment):

TABLE 1 OF § 1065.530.—STATISTICAL CRITERIA FOR VALIDATING TEST CYCLES FOR SPARK-IGNITION ENGINES

	Speed	Torque	Power
1. Slope of the regression line (m)	0.950 to 1.030	0.830 to 1.030	0.880 to 1.030.
2. Y intercept of the regression line (b)	$\|b\| \le 50$ rpm	$\|b\| \le 5.0$ percent of maximum torque from power map.	$\|b\| \le 3.0$ percent of maximum torque from power map.
3. Standard error of the estimate of Y on X (SE).	100 rpm	15 percent of maximum torque from power map.	10 percent of maximum power from power map.
4. Coefficient of determination (r^2)	$r^2 \ge 0.970$	$r^2 \ge 0.880$	$r^2 \ge 0.900$.

TABLE 2 OF § 1065.530.—STATISTICAL CRITERIA FOR VALIDATING TEST CYCLES FOR COMPRESSION-IGNITION ENGINES

	Speed	Torque	Power
1. Slope of the regression line (m)	0.950 to 1.030	0.830 to 1.030 (hot); 0.77 to 1.03 (cold).	0.890 to 1.030 (hot); 0.870 to 1.030 (cold).
2. Y intercept of the regression line (b)	$\|b\| \le 50$ rpm	$\|b\| \le 20$ Nm or $\|b\| \le 2.0$ percent of maximum torque from power map, whichever is greater.	$\|b\| \le 4.0$ kW or $\|b\| \le 3.0$ percent of maximum torque from power map, whichever is greater.
3. Standard error of the estimate of Y on X (SE).	100 rpm	13 percent of maximum torque from power map.	8 percent of maximum power from power map.
4. Coefficient of determination (r^2)	$r^2 \ge 0.970$	$r^2 \ge 0.880$ (hot); $r^2 \ge 0.850$ (cold); ...	$r^2 \ge 0.910$ (hot); $r^2 \ge 0.850$ (cold).

* * * * *

(d) *Transient testing with constant-speed engines.* For constant-speed engines with installed governor operating over a transient duty cycle, the test cycle validation criteria in this section apply to engine-torque values but not engine-speed values.

(e) *Omissions.* You may omit the following points from duty cycle statistics calculations:

(1) Feedback torque and power during motoring reference commands when operator demand is at its minimum.

(2) Feedback speed and power during idle-speed oscillations, if all the following are true:

(i) Reference command is 0% speed and 0% torque.

(ii) Operator demand (*i.e.*, throttle) is at its minimum.

(iii) Absolute value of feedback torque is less than the sum of the reference torque plus 2% of the maximum mapped torque.

(3) Feedback power and either speed or torque for a given point when approaching maximum demand, if all the following are true:

(i) Operator demand (*i.e.*, throttle) is at its maximum.

(ii) Either feedback speed is less than reference speed or feedback torque is less than reference torque, but both are not less than their respective reference values.

(4) Feedback power and either speed or torque for a given point, when approaching minimum demand, if all the following are true:

(i) Operator demand (*i.e.*, throttle) is at its minimum.

(ii) Either feedback speed is greater than 105% of reference speed or feedback torque is greater than 105% of reference torque, but both are not greater than these values.

■ 103. Section 1065.615 is amended by revising paragraphs (c), (d), and (e) to read as follows:

§ 1065.615 Bag sample calculations.

* * * * *

(c) Calculate total brake work (kW-hr) done during the emissions sampling period of each segment or mode and then weight it by the applicable test cycle weighting factors.

(d) Calculate emissions in g/kW-hr by dividing the total weighted mass emission rate (g/test) by the total cycle-weighted brake work for the test.

(e) Apply deterioration factors or other adjustment factors to the brake-specific emission rate in paragraph (d) of this section, as specified in the standard-setting part.

■ 104. Section 1065.620 is added to subpart G to read as follows:

§ 1065.620 Continuous sample analysis and calculations.

Use the sample analysis procedures and calculations of 40 CFR part 86, subpart N, for continuous samples.

■ 105. Section 1065.701 is added to subpart H to read as follows:

§ 1065.701 Particulate measurements.

Use the particulate sampling system and procedures specified in 40 CFR part 86, subpart N, to measure particulate emissions from compression-ignition nonroad engines.

■ 106. Section 1065.910 is revised to read as follows:

§ 1065.910 Measurement accuracy and precision.

Measurement systems used for field testing have accuracy and precision comparable to those of dynamometer testing. Measurement systems that conform to the provisions of §§ 1065.915 through 1065.950 are deemed to be in compliance with the accuracy and precision requirements of paragraph of this section. If you use other field testing measurement systems you need to have documentation indicating that it is comparable to a dynamometer system.

(a) The two systems must be calibrated independently to NIST traceable standards or equivalent national standards for this comparison. We may approve the use of other standards. Calculations of emissions results for this test should be consistent with the field testing data reduction scheme for both the in-use equipment and the dynamometer equipment, and each complete test cycle will be considered one "summing interval", Si as defined in the field-testing data reduction scheme.

(b) While other statistical analyses may be acceptable, we recommend that the comparison be based on a minimum of seven (7) repeats of colocated and simultaneous tests. Perform this comparison over the applicable steady-state and transient test cycles using an engine that is fully warmed up such that its coolant temperature is thermostatically controlled. If there is no applicable transient test cycle, use the applicable steady-state cycle. Anyone who intends to submit an alternative comparison is encouraged to first contact EPA Office of Transportation and Air Quality, Assessment and Standards Division to discuss the applicant's intended statistical analysis. The Division may provide further guidance specific to the appropriate statistical analysis for the respective application.

(c) The following statistical tests are suggested. If the comparison is paired, it must demonstrate that the alternate system passes a two-sided, paired t-test. If the test is unpaired, it must demonstrate that the alternate system passes a two-sided, unpaired t-test. The average of these tests for the reference system must return results less than or equal to the applicable emissions standard. The t-test is performed as follows, where "n" equals the number of tests:

(1) Calculate the average of the in-use system results; this is Iavg.

(2) Calculate the average of the results of the system to which the in-use system was Referenced; this is Ravg.

(3) Calculate the "n-1" standard deviations for the in-use and reference averages; these are Isd and Rsd respectively. Form the F ratio: F = (Isd/Rsd) 2. F must be less than the critical F value, Fcrit at a 95% confidence interval for "n-1" degrees of freedom. Table 1 of this section lists 95% confidence interval Fcrit values for n-1 degrees of freedom. Note that n_A represents the number of alternate system samples, while n_R represents the number of reference system samples.

(4) For an unpaired comparison, calculate the t-value:

$$t_{unpaired} = (I_{avg} - R_{avg})/((I_{sd}^2 + R_{sd}^2)/n)^{1/2}$$

(5) For a paired comparison, calculate the "n-1" standard deviation (squared) of the differences, d_i, between the paired results, where "i" represents the i[th] test of n number of tests:

$$S_D^2 = (Sd_i^2 - ((Sd_i)^2/n))/(n-1)$$

(6) For a paired comparison, calculate the t-value:

$$t_{paired} = (I_{avg} - R_{avg})/(S_D^2/n)^{1/2}$$

(d) The absolute value of t must be less than the critical t value, t_{crit} at a 95% confidence interval for "n-1" degrees of freedom.

TABLE 1 OF § 1065.910—95% CONFIDENCE INTERVAL CRITICAL F VALUES FOR F-TEST

nR–1	nI–1	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
6		4.284	4.207	4.147	4.099	4.06	4.027	4	3.976	3.956	3.938	3.922	3.908	3.896	3.884	3.874
7		3.866	3.787	3.726	3.677	3.637	3.603	3.575	3.55	3.529	3.511	3.494	3.48	3.467	3.455	3.445
8		3.581	3.5	3.438	3.388	3.347	3.313	3.284	3.259	3.237	3.218	3.202	3.187	3.173	3.161	3.15
9		3.374	3.293	3.23	3.179	3.137	3.102	3.073	3.048	3.025	3.006	2.989	2.974	2.96	2.948	2.936
10		3.217	3.135	3.072	3.02	2.978	2.943	2.913	2.887	2.865	2.845	2.828	2.812	2.798	2.785	2.774
11		3.095	3.012	2.948	2.896	2.854	2.818	2.788	2.761	2.739	2.719	2.701	2.685	2.671	2.658	2.646
12		2.996	2.913	2.849	2.796	2.753	2.717	2.687	2.66	2.637	2.617	2.599	2.583	2.568	2.555	2.544
13		2.915	2.832	2.767	2.714	2.671	2.635	2.604	2.577	2.554	2.533	2.515	2.499	2.484	2.471	2.459
14		2.848	2.764	2.699	2.646	2.602	2.565	2.534	2.507	2.484	2.463	2.445	2.428	2.413	2.4	2.388
15		2.79	2.707	2.641	2.588	2.544	2.507	2.475	2.448	2.424	2.403	2.385	2.368	2.353	2.34	2.328
16		2.741	2.657	2.591	2.538	2.494	2.456	2.425	2.397	2.373	2.352	2.333	2.317	2.302	2.288	2.276
17		2.699	2.614	2.548	2.494	2.45	2.413	2.381	2.353	2.329	2.308	2.289	2.272	2.257	2.243	2.23
18		2.661	2.577	2.51	2.456	2.412	2.374	2.342	2.314	2.29	2.269	2.25	2.233	2.217	2.203	2.191
19		2.628	2.544	2.477	2.423	2.378	2.34	2.308	2.28	2.256	2.234	2.215	2.198	2.182	2.168	2.155
20		2.599	2.514	2.447	2.393	2.348	2.31	2.278	2.25	2.225	2.203	2.184	2.167	2.151	2.137	2.124

TABLE 2 OF § 1065.910.—95% CONFIDENCE INTERVAL CRITICAL T VALUES FOR T-TEST

n-1	t_{crit}
6	2.45
7	2.36
8	2.31
9	2.26
10	2.23
11	2.20
12	2.18
13	2.16
14	2.14
15	2.13
16	2.12
17	2.11
18	2.10
19	2.09

TABLE 2 OF § 1065.910.—95% CONFIDENCE INTERVAL CRITICAL T VALUES FOR T-TEST—Continued

n-1	t_{crit}
20	2.09

■ 107. Section 1065.1001 is amended by adding the definition for "Operator demand" in alphabetical order to read as follows:

§ 1065.1001 Definitions.

* * * * *

Operator demand means an engine operator's input to control engine output. The operator may be a person, a governor, or other controller that mechanically or electronically signals an input that demands engine output. Input may be an accelerator pedal or signal, a throttle-control lever or signal, a fuel lever or signal, a speed lever or signal, or a governor setpoint or signal. Output means engine power, P, which is the product of engine speed, ", and engine torque, T.

* * * * *

■ 108. Section 1065.1010 is amended by revising the entry for ASTM D 86–01 and by adding the following entries to Table 1 in alphanumeric order to read as follows:

§ 1065.1010 Reference materials.

(a) * * *

TABLE 1 OF § 1065.1010.—ASTM MATERIALS

Document number and name	Part 1065 reference
ASTM D 86–01, Standard Test Method for Distillation of Petroleum Products at Atmospheric Pressure	1065.205, 1065.210
* * * * * *	*
ASTM D 93–02a, Standard Test Methods for Flash Point by Pensky-Martens Closed Cup Tester	1065.205
ASTM D 287–92, (Reapproved 2000), Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)	1065.205
* * * * * *	*
ASTM D 445–03, Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)	1065.205
ASTM D 613–03b, Standard Test Method for Cetane Number of Diesel Fuel Oil	1065.205
ASTM D 976–91 (Reapproved 2000), Standard Test Methods for Calculated Cetane Index of Distillate Fuels	1065.205
* * * * * *	*
ASTM D 2622–03, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry	1065.205
* * * * * *	*
ASTM D 5186–03, Standard Test Method for Determination of the Aromatic Content and Polynuclear Aromatic Content of Diesel Fuels and Aviation Turbine Fuels By Supercritical Fluid Chromatography	1065.205

* * * * *

PART 1068—GENERAL COMPLIANCE PROVISIONS FOR NONROAD PROGRAMS

■ 109. The authority citation for part 86 continues to read as follows:

Authority: 42 U.S.C. 7401–7671(q).

■ 110. Section 1068.1 is amended by revising paragraphs (a), (b)(5), and (d) and adding paragraph (e) to read as follows:

§ 1068.1 Does this part apply to me?

(a) The provisions of this part apply to everyone with respect to the following engines and to equipment using the following engines (including owners, operators, parts manufacturers, and persons performing maintenance).

(1) Large nonroad spark-ignition engines we regulate under 40 CFR part 1048.

(2) Recreational SI engines and vehicles that we regulate under 40 CFR part 1051 (such as snowmobiles and off-highway motorcycles).

(3) Land-based nonroad diesel engines that we regulate under 40 CFR part 1039.

(b) * * *

(5) Land-based nonroad diesel engines that we regulate under 40 CFR part 89.

* * * * *

(d) Paragraph (a)(1) of this section identifies the parts of the CFR that define emission standards and other requirements for particular types of engines and vehicles. This part 1068 refers to each of these other parts generically as the "standard-setting part." For example, 40 CFR part 1051 is always the standard-setting part for snowmobiles. Follow the provisions of the standard-setting part if they are different than any of the provisions in this part.

(e)(1) The provisions of §§ 1068.30, 1068.310, and 1068.320 apply for stationary spark-ignition engines built on or after January 1, 2004, and for stationary compression-ignition engines built on or after January 1, 2006.

(2) The provisions of §§ 1068.30 and 1068.235 apply for the types of engines listed in paragraph (a) of this section beginning January 1, 2004, where they are used solely for competition.

■ 111. Section 1068.5 is amended by revising paragraphs (a) and (e) to read as follows:

§ 1068.5 How must manufacturers apply good engineering judgment?

(a) You must use good engineering judgment for decisions related to any requirements under this chapter. This includes your applications for certification, any testing you do to show that your certification, production-line, and in-use engines comply with requirements that apply to them, and how you select, categorize, determine, and apply these requirements.

* * * * *

(e) If you disagree with our conclusions, you may file a request for a hearing with the Designated Officer as described in subpart G of this part. In your request, specify your objections, include data or supporting analysis, and get your authorized representative's signature. If we agree that your request raises a substantial factual issue, we will hold the hearing according to subpart F of this part.

■ 112. Section 1068.10 is amended by revising the section heading to read as follows:

§ 1068.10 What provisions apply to confidential information?

■ 113. Section 1068.25 is amended by revising paragraph (b) to read as follows:

§ 1068.25 What information must I give to EPA?

* * * * *

(b) You must establish and maintain records, perform tests, make reports and provide additional information that we may reasonably require under section 208 of the Act (42 U.S.C. 7542). This also applies to engines we exempt from emission standards or prohibited acts.

■ 114. A new § 1068.27 is added to read as follows:

§ 1068.27 May EPA conduct testing with my production engines?

If we request it, you must make a reasonable number of production-line engines available for a reasonable time so we can test or inspect them for compliance with the requirements of this chapter.

■ 115. Section 1068.30 is amended by revising the definitions for "Act", "Certificate holder", "Emission-related defect", "Engine-based", "Engine manufacturer", "Equipment-based", "Equipment manufacturer", "Manufacturer", "Nonroad engine", "Operating hours", and "Ultimate purchaser", and "U.S.-directed production volume" and adding definitions for "Aftertreatment" and in alphabetical order to read as follows:

§ 1068.30 What definitions apply to this part?

* * * * *

Act means the Clean Air Act, as amended, 42 U.S.C. 7401–7671q.

Aftertreatment means relating to a catalytic converter, particulate filter, or any other system, component, or technology mounted downstream of the exhaust valve (or exhaust port) whose design function is to reduce emissions in the engine exhaust before it is exhausted to the environment. Exhaust-gas recirculation (EGR) is not aftertreatment.

* * * * *

Certificate holder means a manufacturer (including importers) with a currently valid certificate of conformity for at least one engine family in a given model year.

* * * * *

Emission-related defect means a defect in design, materials, or workmanship (in an emission-control device or vehicle component or system) that affects an emission-related component, parameter, or specification that is identified in Appendix I or Appendix II of this part. Using an incorrect emission-related component is an emission-related defect.

* * * * *

Engine-based means having emission standards in units of grams of pollutant per kilowatt-hour, and which apply to the engine. Emission standards are either engine-based or equipment-based.

Engine manufacturer means the manufacturer that is subject to the certification requirements of the standard-setting part. For vehicles and equipment subject to this part and regulated under vehicle-based or equipment-based standards, the term engine manufacturer in this part includes vehicle and equipment manufacturers.

Equipment-based means having emission standards that apply to the equipment in which an engine is used, without regard to how the emissions are measured. Where equipment-based standards apply, we require that the equipment be certified, rather than just the engine. Emission standards are either engine-based or equipment-based.

Equipment manufacturer means any company manufacturing a piece of equipment (such as a vehicle).

Manufacturer has the meaning given in section 216(1) of the Act (42 U.S.C. 7550(1)). In general, this term includes any person who manufactures an engine or vehicle for sale in the United States or otherwise introduces a new engine or vehicle into commerce in the United States. This includes importers that import new engines or new equipment into the United States for resale. It also includes secondary engine manufacturers, as described in § 1068.255.

* * * * *

Nonroad engine means:

(1) Except as discussed in paragraph (2) of this definition, a nonroad engine is any internal combustion engine:

(i) In or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as garden tractors, off-highway mobile cranes and bulldozers); or

(ii) In or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers); or

(iii) That, by itself or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.

(2) An internal combustion engine is not a nonroad engine if:

(i) The engine is used to propel a motor vehicle, an aircraft, or equipment used solely for competition, or is subject to standards promulgated under section 202 of the Act (42 U.S.C. 7521); or

(ii) The engine is regulated by a federal New Source Performance Standard promulgated under section 111 of the Act (42 U.S.C. 7411); or

(iii) The engine otherwise included in paragraph (1)(iii) of this definition remains or will remain at a location for more than 12 consecutive months or a shorter period of time for an engine located at a seasonal source. A location is any single site at a building, structure, facility, or installation. Any engine (or engines) that replaces an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. An engine located at a seasonal source is an engine that remains at a seasonal source during the full annual operating period of the seasonal source. A seasonal source is a stationary source that remains in a single location on a permanent basis (*i.e.*, at least two years) and that operates at that single location approximately three months (or more) each year. This paragraph (2)(iii) does not apply to an engine after the engine is removed from the location.

Operating hours means:

(1) For engine storage areas or facilities, times during which people other than custodians and security personnel are at work near, and can access, a storage area or facility.

(2) For other areas or facilities, times during which an assembly line operates or any of the following activities occurs:

(i) Testing, maintenance, or service accumulation.

(ii) Production or compilation of records.

(iii) Certification testing.

(iv) Translation of designs from the test stage to the production stage.

(v) Engine manufacture or assembly.

* * * * *

Ultimate purchaser means the first person who in good faith purchases a new nonroad engine or new piece of equipment for purposes other than resale.

* * * * *

U.S.-directed production volume means the number of engine units, subject to the requirements of this part, produced by a manufacturer for which the manufacturer has a reasonable assurance that sale was or will be made to ultimate purchasers in the United States.

* * * * *

■ 116. Section 1068.101 is amended by revising paragraphs (a) and (b) to read as follows:

§ 1068.101 What general actions does this regulation prohibit?

* * * * *

(a) The following prohibitions and requirements apply to manufacturers of new engines and manufacturers of equipment containing these engines, except as described in subparts C and D of this part:

(1) *Introduction into commerce.* You may not sell, offer for sale, or introduce or deliver into commerce in the United States or import into the United States any new engine or equipment after emission standards take effect for that engine or equipment, unless it has a valid certificate of conformity for its model year and the required label or tag. You also may not take any of the actions listed in the previous sentence with respect to any equipment containing an engine subject to this part's provisions, unless the engine has a valid and appropriate certificate of conformity and the required engine label or tag. For purposes of this paragraph (a)(1), an appropriate certificate of conformity is one that applies for the same model year as the model year of the equipment (except as allowed by § 1068.105(a)), covers the appropriate category of engines (such as locomotive or CI marine), and conforms to all requirements specified for equipment in the standard-setting part. The requirements of this paragraph (a)(1) also cover new engines you produce to replace an older engine in a piece of equipment, unless the engine qualifies for the replacement-engine exemption in § 1068.240. We may assess a civil penalty up to $31,500 for each engine in violation.

(2) *Reporting and recordkeeping.* This chapter requires you to record certain types of information to show that you meet our standards. You must comply with these requirements to make and maintain required records (including those described in § 1068.501). You may not deny us access to your records or the ability to copy your records if we have the authority to see or copy them. Also, you must give us the required reports or information without delay. Failure to comply with the requirements of this paragraph is prohibited. We may assess a civil penalty up to $31,500 for each day you are in violation.

(3) *Testing and access to facilities.* You may not keep us from entering your facility to test engines or inspect if we are authorized to do so. Also, you must perform the tests we require (or have the tests done for you). Failure to perform this testing is prohibited. We may assess a civil penalty up to $31,500 for each day you are in violation.

(b) The following prohibitions apply to everyone with respect to the engines to which this part applies:

(1) *Tampering.* You may not remove or disable a device or element of design that may affect an engine's emission levels. This restriction applies before and after the engine is placed in service. Section 1068.120 describes how this applies to rebuilding engines. For a manufacturer or dealer, we may assess a civil penalty up to $31,500 for each engine in violation. For anyone else, we may assess a civil penalty up to $3,150 for each engine in violation. This prohibition does not apply in any of the following situations:

(i) You need to repair an engine and you restore it to proper functioning when the repair is complete.

(ii) You need to modify an engine to respond to a temporary emergency and you restore it to proper functioning as soon as possible.

(iii) You modify a new engine that another manufacturer has already certified to meet emission standards and recertify it under your own engine family. In this case you must tell the original manufacturer not to include the modified engines in the original engine family.

(2) *Defeat devices.* You may not knowingly manufacture, sell, offer to sell, or install, an engine part if it bypasses, impairs, defeats, or disables the engine's control the emissions of any pollutant. We may assess a civil penalty up to $3,150 for each part in violation.

(3) *Stationary engines.* For an engine that is excluded from any requirements of this chapter because it is a stationary engine, you may not move it or install it in any mobile equipment, except as allowed by the provisions of this chapter. You may not circumvent or attempt to circumvent the residence-time requirements of paragraph (2)(iii) of the nonroad engine definition in § 1068.30. We may assess a civil penalty up to $31,500 for each day you are in violation.

(4) *Competition engines.* For an uncertified engine or piece of equipment that is excluded or exempted from any requirements of this chapter because it is to be used solely for competition, you may not use it in a manner that is inconsistent with use solely for competition. We may assess a civil penalty up to $31,500 for each day you are in violation.

(5) *Importation.* You may not import an uncertified engine or piece of equipment if it is defined to be new in the standard-setting part and it is built after emission standards start to apply in the United States. We may assess a civil penalty up to $31,500 for each day you are in violation. Note the following:

(i) The definition of new is broad for imported engines; uncertified engines and equipment (including used engines and equipment) are generally considered to be new when imported.

(ii) Engines that were originally manufactured before applicable EPA standards were in effect are generally not subject to emission standards.

(6) *Warranty.* You must meet your obligation to honor your emission-related warranty under § 1068.115 and to fulfill any applicable responsibilities to recall engines under § 1068.505. Failure to meet these obligations is prohibited. We may assess a civil penalty up to $31,500 for each engine in violation.

* * * * *

■ 117. Section 1068.105 is amended by revising paragraph (c) and adding introductory text to read as follows:

§ 1068.105 What other provisions apply to me specifically if I manufacture equipment needing certified engines?

This section describes general provisions that apply to equipment manufacturers. See the standard-setting part for any requirements that apply for certain applications.

* * * * *

(c) *Attaching a duplicate label.* If you obscure the engine's label, you must do four things to avoid violating § 1068.101(a)(1):

(1) Send a request for duplicate labels in writing with your company's letterhead to the engine manufacturer. Include the following information in your request:

(i) Identify the type of equipment and the specific engine and equipment models needing duplicate labels.

(ii) Identify the engine family (from the original engine label).

(iii) State the reason that you need a duplicate label for each equipment model.

(iii) Identify the number of duplicate labels you will need.

(2) Permanently attach the duplicate label to your equipment by securing it to a part needed for normal operation and not normally requiring replacement. Make sure an average person can easily read it.

(3) Destroy any unused duplicate labels if you find that you will not need them.

(4) Keep the following records for at least eight years after the end of the model year identified on the engine label:

(i) Keep a copy of your written request.

(ii) Keep drawings or descriptions that show how you apply the duplicate labels to your equipment.

(iii) Maintain a count of those duplicate labels you use and those you destroy.

* * * * *

■ 118. Section 1068.110 is amended by revising paragraphs (b), (c), (d), and (e) to read as follows:

§ 1068.110 What other provisions apply to engines in service?

* * * * *

(b) *Certifying aftermarket parts.* As the manufacturer or rebuilder of an aftermarket engine part, you may—but are not required to—certify according to § 85.2114 of this chapter that using the part will not cause engines to fail to meet emission standards. Whether you certify or not, you must keep any information showing how your parts or service affect emissions.

(c) *Compliance with standards.* We may test engines and equipment to investigate compliance with emission standards and other requirements. We may also require the manufacturer to do this testing.

(d) *Defeat devices.* We may test engines and equipment to investigate potential defeat devices. We may also require the manufacturer to do this testing. If we choose to investigate one of your designs, we may require you to show us that it does not have a defeat device. To do this, you may have to share with us information regarding test programs, engineering evaluations, design specifications, calibrations, on-board computer algorithms, and design strategies. It is a violation of the Act for anyone to make, install or use defeat devices. See § 1068.101(b)(2) and the standard-setting part.

(e) *Warranty and maintenance.* Owners are responsible for properly maintaining their engines; however, owners may make warranty claims against the manufacturer for emission-related parts, as described in § 1068.115. The warranty period begins when the engine is first placed into service. See the standard-setting part for specific requirements. It is a violation of the Act for anyone to disable emission controls; see § 1068.101(b)(1) and the standard-setting part.

■ 119. Section 1068.120 is amended by revising paragraphs (b)(2), (c), (d), (f), and (h) to read as follows:

§ 1068.120 What requirements must I follow to rebuild engines?

* * * * *

(b) * * *

(2) Unscheduled maintenance that occurs commonly within the useful life period. For example, replacing a water pump is not rebuilding an engine.

(c) For maintenance or service that is not rebuilding, you may not make changes that might increase emissions of any pollutant, but you do not need to keep any records.

(d) If you rebuild an engine or engine system, you must have a reasonable technical basis for knowing that the rebuilt engine's emission-control system performs as well as, or better than, it performs in its certified configuration. Identify the model year of the resulting engine configuration. You have a reasonable basis if you meet two main conditions:

(1) Install parts—new, used, or rebuilt—so a person familiar with engine design and function would reasonably believe that the engine with those parts will control emissions of all pollutants at least to the same degree as with the original parts. For example, it would be reasonable to believe that parts performing the same function as the original parts (and to the same degree) would control emissions to the same degree as the original parts.

(2) Adjust parameters or change design elements only according to the original engine manufacturer's instructions. Or, if you differ from these instructions, you must have data or some other technical basis to show you should not expect in-use emissions to increase.

* * * * *

(f) If the rebuilt engine replaces another certified engine in a piece of equipment, you must rebuild it to a certified configuration of the same model year as, or a later model year than, the engine you are replacing.

* * * * *

(h) When you rebuild an engine, check, clean, adjust, repair, or replace all emission-related components (listed in Appendix I of this part) as needed according to the original manufacturer's recommended practice. In particular, replace oxygen sensors, replace the catalyst if there is evidence of malfunction, clean gaseous fuel system components, and replace fuel injectors (if applicable), unless you have a reasonable technical basis for believing any of these components do not need replacement.

* * * * *

■ 120. Section 1068.125 is amended by revising paragraphs (a)(1)(iv), (b)(3), and (e)(2) to read as follows:

§ 1068.125 What happens if I violate the regulations?

(a) * * *

(1) * * *

(iv) Your history of compliance with Title II of the Act (42 U.S.C. 7401–7590).

* * * * *

(b) * * *

(3) We will not pursue an administrative penalty for a particular violation if either of the following two conditions is true:

(i) We are separately prosecuting the violation under this subpart.

(ii) We have issued a final order for a violation, no longer subject to judicial review, for which you have already paid a penalty.

* * * * *

(e) * * *

(2) In addition, if you do not pay the full amount of a penalty on time, you must then pay more to cover interest, enforcement expenses (including attorney's fees and costs for collection), and a quarterly nonpayment penalty for each quarter you do not pay. The quarterly nonpayment penalty is 10 percent of your total penalties plus any unpaid nonpayment penalties from previous quarters.

■ 121. Section 1068.201 is amended by revising the introductory text and paragraph (i) to read as follows:

§ 1068.201 Does EPA exempt or exclude any engines from the prohibited acts?

We may exempt new engines from some or all of the prohibited acts or requirements of this part under provisions described in this subpart. We may exempt an engine already placed in service in the United States from the prohibition in § 1068.101(b)(1) if the exemption for engines used solely for competition applies (see § 1068.235). In addition, see § 1068.1 and the standard-setting parts to determine if other engines are excluded from some or all of the regulations in this chapter.

* * * * *

(i) If you want to take an action with respect to an exempted or excluded engine that is prohibited by the exemption or exclusion, such as selling it, you need to certify the engine. We will issue a certificate of conformity if you send us an application for certification showing that you meet all the applicable requirements from the standard-setting part. Also, in some cases, we may allow manufacturers to modify the engine as needed to make it identical to engines already covered by a certificate. We would base such an approval on our review of any appropriate documentation. These engines must have emission control information labels that accurately describe their status.

■ 122. Section 1068.210 is amended by revising paragraphs (d)(5)(iv) and (e)(3)(iv) to read as follows:

§ 1068.210 What are the provisions for exempting test engines?

* * * * *

(d) * * *

(5) * * *

(iv) Ownership and control of the engines involved in the test.

(e) * * *

(3) * * *

(iv) The statement "THIS ENGINE IS EXEMPT UNDER 40 CFR 1068.210 OR 1068.215 FROM EMISSION STANDARDS AND RELATED REQUIREMENTS.".

* * * * *

■ 123. Section 1068.215 is amended by revising paragraphs (b), (c)(3)(iii), and (c)(3)(iv) to read as follows:

§ 1068.215 What are the provisions for exempting manufacturer-owned engines?

* * * * *

(b) An engine may be exempt without a request if it is a nonconforming engine under your ownership and control and you operate it to develop products, assess production methods, or promote your engines in the marketplace. You may not loan, lease, sell, or use the engine to generate revenue, either by itself or in a piece of equipment.

(c) * * *

(3) * * *

(iii) Engine displacement, engine family identification (as applicable), and model year of the engine or whom to contact for further information.

(iv) The statement "THIS ENGINE IS EXEMPT UNDER 40 CFR 1068.210 OR 1068.215 FROM EMISSION STANDARDS AND RELATED REQUIREMENTS.".

■ 124. Section 1068.220 is amended by revising paragraphs (b) and (e)(3) to read as follows:

§ 1068.220 What are the provisions for exempting display engines?

* * * * *

(b) A nonconforming display engine will be exempted if it is used only for displays in the interest of a business or the general public. This exemption does not apply to engines displayed for private use, private collections, or any other purpose we determine is inappropriate for a display exemption.

* * * * *

(e) * * *

(3) Engine displacement, engine family identification (as applicable), and model year of the engine or whom to contact for further information.

* * * * *

■ 125. Section 1068.225 is amended by adding paragraph (d) to read as follows:

§ 1068.225 What are the provisions for exempting engines for national security?

* * * * *

(d) Add a legible label, written in block letters in English, to each engine exempted under this section. The label must be permanently secured to a readily visible part of the engine needed for normal operation and not normally requiring replacement, such as the engine block. This label must include at least the following items:

(1) The label heading "EMISSION CONTROL INFORMATION".

(2) Your corporate name and trademark.

(3) Engine displacement, engine family identification (as applicable), and model year of the engine or whom to contact for further information.

(4) The statement "THIS ENGINE HAS AN EXEMPTION FOR NATIONAL SECURITY UNDER 40 CFR 1068.225.".

■ 126. Section 1068.230 is amended by revising paragraph (c) to read as follows:

§ 1068.230 What are the provisions for exempting engines for export?

* * * * *

(c) Label each exempted engine and shipping container with a label or tag showing the engine is not certified for sale or use in the United States. These labels need not be permanently attached to the engines. The label must include at least the statement "THIS ENGINE IS SOLELY FOR EXPORT AND IS THEREFORE EXEMPT UNDER 40 CFR 1068.230 FROM U.S. EMISSION STANDARDS AND RELATED REQUIREMENTS.".

■ 127. Section 1068.235 is amended by revising paragraph (c) to read as follows:

§ 1068.235 What are the provisions for exempting engines used solely for competition?

* * * * *

(c) If you modify an engine under paragraph (b) of this section, you must destroy the original emission label. If you loan, lease, sell, or give one of these engines to someone else, you must tell the new owner (or operator, if applicable) in writing that it may be used only for competition.

■ 128. Section 1068.240 is revised to read as follows:

§ 1068.240 What are the provisions for exempting new replacement engines?

(a) You are eligible for the exemption for new replacement engines only if you are a certificate holder.

(b) The prohibitions in § 1068.101(a)(1) do not apply to an engine if all the following conditions apply:

(1) You produce a new engine to replace an engine already placed in service in a piece of equipment.

(2) The engine being replaced was manufactured before the emission standards that would otherwise apply to the new engine took effect.

(3) You determine that you do not produce an engine certified to meet current requirements that has the appropriate physical or performance characteristics to repower the equipment. If the engine being replaced was made by a different company, you must make this determination also for engines produced by this other company.

(4) You or your agent takes possession of the old engine or confirms that the engine has been destroyed.

(5) You make the replacement engine in a configuration identical in all material respects to the engine being replaced (or that of another certified engine of the same or later model year). This requirement applies only if the old engine was certified to emission standards less stringent than those in effect when you produce the replacement engine.

(c) If the engine being replaced was not certified to any emission standards under this chapter, add a permanent label with your corporate name and trademark and the following language:

THIS ENGINE DOES NOT COMPLY WITH U.S. EPA NONROAD EMISSION REQUIREMENTS. SELLING OR INSTALLING THIS ENGINE FOR ANY PURPOSE OTHER THAN TO REPLACE A NONROAD ENGINE BUILT BEFORE JANUARY 1, [Insert appropriate year reflecting when the earliest tier of standards began to apply to engines of that size and type] MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.

(d) If the engine being replaced was certified to emission standards less stringent than those in effect when you produce the replacement engine, add a permanent label with your corporate name and trademark and the following language:

THIS ENGINE DOES NOT COMPLY WITH U.S. EPA NONROAD EMISSION REQUIREMENTS. SELLING OR INSTALLING THIS ENGINE FOR ANY PURPOSE OTHER THAN TO REPLACE A NONROAD ENGINE BUILT BEFORE JANUARY 1, [Insert appropriate year reflecting when the next tier of emission standards began to apply] MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.

(e) The provisions of this section may not be used to circumvent emission standards that apply to new engines under the standard-setting part.

■ 129. Section 1068.245 is amended by revising paragraphs (a) introductory text and (e) to read as follows:

§ 1068.245 What temporary provisions address hardship due to unusual circumstances?

(a) After considering the circumstances, we may permit you to introduce into commerce engines or equipment that do not comply with emission-related requirements for a limited time if all the following conditions apply:

* * * * *

(e) We may include reasonable additional conditions on an approval granted under this section, including provisions to recover or otherwise address the lost environmental benefit or paying fees to offset any economic gain resulting from the exemption. For example, in the case of multiple tiers of emission standards, we may require that you meet the standards from the previous tier.

* * * * *

■ 130. Section 1068.250 is amended by revising paragraphs (d)(2), (d)(4), and (j) to read as follows:

§ 1068.250 What are the provisions for extending compliance deadlines for small-volume manufacturers under hardship?

* * * * *

(d) * * *

(2) Describe your current and projected financial status, with and without the burden of complying fully with the applicable regulations in this chapter.

* * * * *

(4) Identify the engineering and technical steps you have taken or those you plan to take to comply with regulations in this chapter.

* * * * *

(j) We will approve extensions of up to one model year. We may review and revise an extension as reasonable under the circumstances.

* * * * *

■ 131. Section 1068.255 is amended by revising paragraph (c) introductory text to read as follows:

§ 1068.255 What are the provisions for exempting engines for hardship for equipment manufacturers and secondary engine manufacturers?

* * * * *

(c) *Secondary engine manufacturers.* As a secondary engine manufacturer, you may ask for approval to produce exempted engines under this section for up to 12 months. We may require you to certify your engines to compliance levels above the emission standards that apply. For example, the in the case of multiple tiers of emission standards, we may require you to meet the standards from the previous tier.

* * * * *

■ 132. A new § 1068.260 is added to subpart C to read as follows:

§ 1068.260 What are the provisions for temporarily exempting engines for delegated final assembly?

(a) Shipping an engine separately from an aftertreatment component that you have specified as part of its certified configuration will not be a violation of the prohibitions in § 1068.101(a)(1), if you do all the following:

(1) Apply for and receive a certificate of conformity for the engine and its emission-control system before shipment.

(2) Provide installation instructions in enough detail to ensure that the engine will be in its certified configuration if someone follows these instructions.

(3) Have a contractual agreement with an equipment manufacturer obligating the equipment manufacturer to complete the final assembly of the engine so it is in its certified configuration when installed in the equipment. This agreement must also obligate the equipment manufacturer to provide the affidavits and cooperate with the audits required under paragraph (a)(6) of this section.

(4) Include the cost of all aftertreatment components in the cost of the engine.

(5) Ship the aftertreatment components directly to the equipment manufacturer, or arrange for separate shipment by the component manufacturer directly to the equipment manufacturer.

(6) Take appropriate additional steps to ensure that all engines will be in their certified configuration when installed by the equipment manufacturer. At a minimum do the following:

(i) Obtain annual affidavits from every equipment manufacturer to whom you, your distributors, or your dealers sell engines under this section. The affidavits must list the part numbers of the aftertreatment devices that equipment manufacturers install on each engine they purchase from you, your distributors, or your dealers under this section.

(ii) If you sell more than 50 engines per model year under this section, you must annually audit four equipment manufacturers to whom you sell engines under this section. To select individual equipment manufacturers, divide all the affected equipment manufacturers into quartiles based on the number of engines they buy from you; select a single equipment manufacturer from each quartile each model year. Vary the equipment manufacturers you audit from year to year, though you may repeat an audit in a later model year if you find or suspect that a particular equipment manufacturer is not properly installing aftertreatment devices. If you sell engines to fewer than 16 equipment manufacturers under the provisions of this section, you may instead set up a plan to audit each equipment manufacturer on average once every four model years. Audits must involve the assembling companies' facilities, procedures, and production records to monitor their compliance with your instructions, must include investigation of some assembled engines, and must confirm that the number of aftertreatment devices shipped were sufficient for the number of engines produced. Where an equipment manufacturer is not located in the United States, you may conduct the audit at a distribution or port facility in the United States. You must keep records of these audits and provide a report describing any uninstalled or improperly installed aftertreatment components to us within 90 days of the audit.

(iii) If you sell up to 50 engines per model year under this section, you must conduct audits as described in paragraph (a)(6)(ii) of this section or propose an alternative plan for ensuring that equipment manufacturers properly install aftertreatment devices.

(7) Describe the following things in your application for certification:

(i) How you plan to use the provisions of this section.

(ii) A detailed plan for auditing equipment manufacturers, as described in paragraph (a)(6) of this section.

(iii) All other steps you plan to take under paragraph (a)(6) of this section.

(8) Keep records to document how many engines you produce under this exemption. Also, keep records to document your contractual agreements under paragraph (a)(3) of this section. Keep all these records for five years after the end of the model year and make them available to us upon request.

(9) Make sure the engine has the emission control information label we require under the standard-setting part. Apply an additional temporary label or tag in a way that makes it unlikely that the engine will be installed in equipment other than in its certified configuration. The label or tag must identify the engine as incomplete and include a clear statement that failing to install the aftertreatment device, or otherwise bring the engine into its certified configuration, is a violation of federal law subject to civil penalty.

(b) An engine you produce under this section becomes new when it is fully assembled, except for aftertreatment devices, for the first time. Use this date to determine the engine's model year.

(c) Once the equipment manufacturer takes possession of an engine exempted under this section, the exemption expires and the engine is subject to all the prohibitions in 40 CFR 1068.101.

(d) You must notify us within 15 days if you find from an audit or another source that an equipment manufacturer has failed to meet its obligations under this section.

(e) We may suspend, revoke, or void an exemption under this section, as follows:

(1) We may suspend or revoke your exemption for the entire engine family if we determine that any of the engines are not in their certified configuration after installation in the equipment, or if you fail to comply with the requirements of this section. If we suspend or revoke the exemption for any of your engine families under this paragraph (d), this exemption will not apply for future certificates unless you demonstrate that the factors causing the nonconformity do not apply to the other engine families. We may suspend or revoke the exemption for shipments to a single facility where final assembly occurs.

(2) We may void your exemption for the entire engine family if you intentionally submit false or incomplete information or fail to keep and provide to EPA the records required by this section.

(f) You are liable for the in-use compliance of any engine that is exempt under this section. It is also a violation of § 1068.101(b)(1) for any person to complete assembly of the exempted engine without complying fully with the installation instructions.

■ 133. Section 1068.305 is amended by revising paragraphs (a) and (e) to read as follows:

§ 1068.305 How do I get an exemption or exclusion for imported engines?

(a) Complete the appropriate EPA declaration form before importing any nonconforming engine. These forms are available on the Internet at *http://www.epa.gov/OTAQ/imports/* or by phone at 202–564–9660.

* * * * *

(e) Meet the requirements specified for the appropriate exemption in this part or the standard-setting part, including any labeling requirements that apply.

■ 134. Section 1068.310 is revised to read as follows:

§ 1068.310 What are the exclusions for imported engines?

If you show us that your engines qualify under one of the paragraphs of this section, we will approve your request to import such excluded engines. You must have our approval to import an engine under paragraph (a) of this section. You may, but are not required to request our approval to import the engines under paragraph (b) or (c) of this section. The following engines are excluded:

(a) *Engines used solely for competition.* Engines that you demonstrate will be used solely for competition are excluded from the restrictions on imports in § 1068.301(b), but only if they are properly labeled. See the standard-setting part for provisions related to this demonstration. Section 1068.101(b)(4) prohibits anyone from using these excluded engines for purposes other than competition.

(b) *Stationary engines.* The definition of nonroad engine in 40 CFR 1068.30 does not include certain engines used in stationary applications. Such engines are not subject to the restrictions on imports in § 1068.301(b), but only if they are properly labeled. Section 1068.101 restricts the use of stationary engines for non-stationary purposes.

(c) *Other engines.* The standard-setting parts may exclude engines used in certain applications. For example, engines used in aircraft and very small engines used in hobby vehicles are generally excluded. Engines used in underground mining are excluded if they are regulated by the Mine Safety and Health Administration.

■ 135. Section 1068.315 is amended by revising the introductory text and paragraph (a) and adding paragraph (f)(1)(iii) to read as follows:

§ 1068.315 What are the permanent exemptions for imported engines?

We may approve a permanent exemption from the restrictions on imports under § 1039.301(b) under the following conditions:

(a) *National security exemption.* You may import an engine under the national security exemption in § 1068.225, but only if it is properly labeled.

* * * * *

(f) * * *

(1) * * *

(iii) Land-based nonroad diesel engines (see part 1039 of this chapter).

* * * * *

■ 136. Section 1068.320 is amended by revising the section heading and paragraphs (a) introductory text and (b) to read as follows:

§ 1068.320 How must I label an imported engine with an exclusion or a permanent exemption?

(a) For engines imported under § 1068.310(a) or (b), you must place a permanent label or tag on each engine. If no specific label requirements in the standard-setting part apply for these engines, you must meet the following requirements:

* * * * *

(b) On the engine label or tag, do the following:

(1) Include the heading "EMISSION CONTROL INFORMATION".

(2) Include your full corporate name and trademark.

(3) State the engine displacement (in liters) and rated power. If the engine's rated power is not established, state the approximate power rating accurately enough to allow a determination of which standards would otherwise apply.

(4) State: "THIS ENGINE IS EXEMPT FROM THE REQUIREMENTS OF [identify the part referenced in 40 CFR 1068.1(a) that would otherwise apply], AS PROVIDED IN [identify the paragraph authorizing the exemption (for example, "40 CFR 1068.315(a)")]. INSTALLING THIS ENGINE IN ANY DIFFERENT APPLICATION MAY BE A VIOLATION OF FEDERAL LAW SUBJECT TO CIVIL PENALTY.".

* * * * *

■ 137. Section 1068.325 is amended by revising the introductory text and paragraphs (a) and (b) and adding paragraph (f) to read as follows:

§ 1068.325 What are the temporary exemptions for imported engines?

If we approve a temporary exemption from the restrictions on importing an engine under § 1039.301(b), you may import it under the conditions in this section. We may ask the U.S. Customs Service to require a specific bond amount to make sure you comply with the requirements of this subpart. You may not sell or lease one of these engines while it is in the United States. You must eventually export the engine as we describe in this section unless you get a certificate of conformity for it or it qualifies for one of the permanent exemptions in § 1068.315. Section 1068.330 specifies an additional temporary exemption allowing you to import certain engines you intend to sell or lease.

(a) *Exemption for repairs or alterations.* You may temporarily import a nonconforming engine under bond solely to repair or alter it or the equipment in which it is installed. You may operate the engine and equipment in the United States only as necessary to repair it, alter it, or ship it to or from the service location. Export the engine directly after servicing is complete.

(b) *Testing exemption.* You may temporarily import a nonconforming engine under bond for testing if you follow the requirements of § 1068.210. You may operate the engine in the United States only to allow testing. This exemption expires one year after you import the engine, unless we approve an extension. The engine must be exported before the exemption expires.

* * * * *

(f) *Delegated assembly exemption.* You may import a nonconforming engine for final assembly, as described in § 1068.260.

■ 138. Section 1068.335 is amended by revising paragraph (a) to read as follows:

§ 1068.335 What are the penalties for violations?

(a) *All imported engines.* Unless you comply with the provisions of this subpart, importation of nonconforming engines violates sections 203 and 213(d) of the Act (42 U.S.C. 7522 and 7547(d)). You may then have to export the engines, or pay civil penalties, or both. The U.S. Customs Service may seize unlawfully imported engines.

* * * * *

■ 139. Section 1068.401 is revised to read as follows:

§ 1068.401 What is a selective enforcement audit?

(a) We may conduct or require you to conduct emission tests on your production engines in a selective enforcement audit. This requirement is independent of any requirement for you to routinely test production-line engines.

(b) If we send you a signed test order, you must follow its directions and the provisions of this subpart. We may tell you where to test the engines. This may be where you produce the engines or any other emission testing facility.

(c) If we select one or more of your engine families for a selective enforcement audit, we will send the test order to the person who signed the application for certification or we will deliver it in person.

(d) If we do not select a testing facility, notify the Designated Officer within one working day of receiving the test order where you will test your engines.

(e) You must do everything we require in the audit without delay.

■ 140. Section 1068.410 is amended by revising paragraphs (e)(1), (g), and (i) to read as follows:

§ 1068.410 How must I select and prepare my engines?

* * * * *

(e) * * *

(1) We may adjust or require you to adjust idle speed outside the physically adjustable range as needed until the engine has stabilized emission levels (see paragraph (f) of this section). We may ask you for information needed to establish an alternate minimum idle speed.

* * * * *

(g) *Damage during shipment.* If shipping an engine to a remote facility for testing under a selective enforcement audit makes necessary an adjustment or repair, you must wait until after the initial emission test to do this work. We may waive this requirement if the test would be impossible or unsafe, or if it would permanently damage the engine. Report to us, in your written report under § 1068.450, all adjustments or repairs you make on test engines before each test.

* * * * *

(i) *Retesting after invalid tests.* You may retest an engine if you determine an emission test is invalid under the standard-setting part. Explain in your written report reasons for invalidating any test and the emission results from all tests. If you retest an engine and, within ten days after testing, ask to substitute results of the new tests for the original ones, we will answer within ten days after we receive your information.

■ 141. Section 1068.415 is amended by revising paragraphs (d) and (e) to read as follows:

§ 1068.415 How do I test my engines?

* * * * *

(d) Accumulate service on test engines at a minimum rate of 6 hours per engine during each 24-hour period. The first 24-hour period for service accumulation begins when you finish preparing an engine for testing. The minimum service accumulation rate does not apply on weekends or holidays. You may ask us to approve a lower service accumulation rate. Plan your service accumulation to allow testing at the rate specified in paragraph (c) of this section. Select engine operation for accumulating operating hours on your test engines to represent normal in-use engine operation for the engine family.

(e) Test engines in the same order you select them.

■ 142. Section 1068.445 is amended by revising paragraph (a)(1) to read as follows:

§ 1068.445 When may EPA revoke my certificate under this subpart and how may I sell these engines again?

(a) * * *

(1) You do not meet the reporting requirements under this subpart.

* * * * *

■ 143. Section 1068.450 is amended by revising paragraph (e) to read as follows:

§ 1068.450 What records must I send to EPA?

* * * * *

(e) We may post test results on publicly accessible databases and we will send copies of your reports to anyone from the public who asks for them. We will not release information about your sales or production volumes, which is all we will consider confidential.

■ 144. Section 1068.501 is revised to read as follows:

§ 1068.501 How do I report engine defects?

This section addresses your responsibility to investigate and report emission-related defects in design, materials, or workmanship. The provisions of this section do not limit your liability under this part or the Clean Air Act. For example, selling an engine that does not conform to your application for certification is a violation of § 1068.101(a)(1), independent of the requirements of this section.

(a) *General provisions.* As an engine manufacturer, you must investigate in certain circumstances whether engines that have been introduced into commerce in the United States have incorrect, improperly installed, or otherwise defective emission-related components or systems. You must also send us reports as specified by this section.

(1) This section addresses defects for any of the following emission-related components, or systems containing the following components:

(i) Electronic control units, aftertreatment devices, fuel-metering components, EGR-system components, crankcase-ventilation valves, all components related to charge-air compression and cooling, and all sensors associated with any of these components.

(ii) Any other component whose primary purpose is to reduce emissions.

(iii) Any other component whose failure might increase emissions of any pollutant without significantly degrading engine performance.

(2) The requirements of this section relate to defects in any of the components or systems identified in paragraph (a)(1) of this section if the defects might affect any of the parameters or specifications in Appendix II of this part or might otherwise affect an engine's emissions of any pollutant.

(3) For the purposes of this section, defects do not include damage to emission-related components or systems (or maladjustment of parameters) caused by owners improperly maintaining or abusing their engines.

(4) The requirements of this section do not apply to emission control information labels. Note however, that § 1068.101(a)(1) prohibits the sale of engines without proper labels, which also applies to misprinted labels.

(5) You must track the information specified in paragraph (b)(1) of this section. You must assess this data at least every three months to evaluate whether you exceed the thresholds specified in paragraphs (e) and (f) of this section. Where thresholds are based on a percentage of engines in the engine family, use actual sales figures for the whole model year when they become available. Use projected sales figures until the actual sales figures become available. You are not required to collect additional information other than that specified in paragraph (b)(1) of this section before reaching a threshold for an investigation specified in paragraph (e) of this section.

(6) You may ask us to allow you to use alternate methods for tracking, investigating, reporting, and correcting emission-related defects. In your request, explain and demonstrate why you believe your alternate system will be at least as effective in the aggregate in tracking, identifying, investigating, evaluating, reporting, and correcting potential and actual emissions-related defects as the requirements in this section. In this case, provide all available data necessary to demonstrate why an alternate system is appropriate for your engines and how it will result in a system at least as effective as that required under this section.

(7) If we determine that emission-related defects result in a substantial number of properly maintained and used engines not conforming to the regulations of this chapter during their useful life, we may order you to conduct a recall of your engines (see § 1068.505).

(8) Send all reports required by this section to the Designated Officer.

(9) This section distinguishes between defects and possible defects. A possible defect exists anytime there is an indication that an emission-related component or system might have a defect, as described in paragraph (b)(1) of this section.

(b) *Investigation of possible defects.* Investigate possible defects as follows:

(1) If the number of engines that have a possible defect, as defined by this paragraph (b)(1), exceeds a threshold specified in paragraph (e) of this section, you must conduct an investigation to determine if an emission-related component or system is actually defective. You must classify an engine component or system as having a possible defect if any of the following sources of information shows there is a significant possibility that a defect exists:

(i) A warranty claim is submitted for the component, whether this is under your emission-related warranty or any other warranty.

(ii) Your quality-assurance procedures suggest that a defect may exist.

(iii) You receive any other information for which good engineering judgment would indicate the component or system may be defective, such as information from dealers, field-service personnel, hotline complaints, or engine diagnostic systems.

(2) If the number of shipped replacement parts for any individual component is high enough that good engineering judgment would indicate a significant possibility that a defect exists, you must conduct an investigation to determine if it is actually defective. Note that this paragraph (b)(2) does not require data-tracking or recording provisions related to shipment of replacement parts.

(3) Your investigation must be prompt, thorough, consider all relevant information, follow accepted scientific and engineering principles, and be designed to obtain all the information specified in paragraph (d) of this section.

(4) Your investigation needs to consider possible defects that occur only within the useful life period, or within five years after the end of the model year, whichever is longer.

(5) You must continue your investigation until you are able to show that there is no emission-related defect or you obtain all the information specified for a defect report in paragraph (d) of this section. Send us an updated defect report anytime you have significant additional information.

(6) If a component with a possible defect is used in additional engine families or model years, you must investigate whether the component may be defective when used in these additional engine families or model years, and include these results in any defect report you send under paragraph (c) of this section.

(7) If your initial investigation concludes that the number of engines with a defect is fewer than any of the thresholds specified in paragraph (f) of this section, but other information later becomes available that may show that the number of engines with a defect exceeds a threshold, then you must resume your investigation. If you resume an investigation, you must include the information from the earlier investigation to determine whether to send a defect report.

(c) *Reporting defects.* You must send us a defect report in either of the following cases:

(1) Your investigation shows that the number of engines with a defect exceeds a threshold specified in paragraph (f) of this section. Send the defect report within 21 days after the date you identify this number of defective engines. See paragraph (h) of this section for reporting requirements that apply if the number of engines with a defect does not exceed any of the thresholds in paragraph (f) of this section.

(2) You know there are emission-related defects for a component or system in a number of engines that exceeds a threshold specified in paragraph (f) of this section, regardless of how you obtain this information. Send the defect report within 21 days after you learn that the number of defects exceeds a threshold.

(d) *Contents of a defect report.* Include the following information in a defect report:

(1) Your corporate name and a person to contact regarding this defect.

(2) A description of the defect, including a summary of any engineering analyses and associated data, if available.

(3) A description of the engines that have the defect, including engine families, models, and range of production dates.

(4) An estimate of the number and percentage of each class or category of affected engines that have the defect, and an explanation of how you

determined this number. Describe any statistical methods you used under paragraph (g)(6) of this section.

(5) An estimate of the defect's impact on emissions, with an explanation of how you calculated this estimate and a summary of any emission data demonstrating the impact of the defect, if available.

(6) A description of your plan for addressing the defect or an explanation of your reasons for not believing the defects must be addressed.

(e) *Thresholds for conducting a defect investigation.* You must begin a defect investigation based on the following number of engines that may have the defect:

(1) For engines with maximum engine power at or below 560 kW:

(i) For engine families with annual sales below 500 units: 50 or more engines.

(ii) For engine families with annual sales from 500 to 50,000 units: more than 10.0 percent of the total number of engines in the engine family.

(iii) For engine families with annual sales above 50,000 units: 5,000 or more engines.

(2) For engines with maximum engine power greater than 560 kW:

(i) For engine families with annual sales below 250 units: 25 or more engines.

(ii) For engine families with annual sales at or above 250 units: more than 10.0 percent of the total number of engines in the engine family.

(f) *Thresholds for filing a defect report.* You must send a defect report based on the following number of engines that have the defect:

(1) For engines with maximum engine power at or below 560 kW:

(i) For engine families with annual sales below 1,000 units: 20 or more engines.

(ii) For engine families with annual sales from 1,000 to 50,000 units: more than 2.0 percent of the total number of engines in the engine family.

(iii) For engine families with annual sales above 50,000 units: 1,000 or more engines.

(2) For engines with maximum engine power greater than 560 kW:

(i) For engine families with annual sales below 150 units: 10 or more engines.

(ii) For engine families with annual sales from 150 to 750 units: 15 or more engines.

(iii) For engine families with annual sales above 750 units: more than 2.0 percent of the total number of engines in the engine family.

(g) *How to count defects.* (1) Track defects separately for each model year and engine family as much as possible. If information is not identifiable by model year or engine family, use good engineering judgment to evaluate whether you exceed a threshold in paragraph (e) or (f) of this section. Consider only your U.S.-directed production volume.

(2) Within an engine family, track defects together for all components or systems that are the same in all material respects. If multiple companies separately supply a particular component or system, treat each company's component or system as unique.

(3) If a possible defect is not attributed to any specific part of the engine, consider the complete engine a distinct component for evaluating whether you exceed a threshold in paragraph (e) of this section.

(4) If you correct defects before they reach the ultimate purchaser as a result of your quality-assurance procedures, count these against the investigation thresholds in paragraph (e) of this section unless you routinely check every engine in the engine family. Do not count any corrected defects as actual defects under paragraph (f) of this section.

(5) Use aggregated data from all the different sources identified in paragraph (b)(1) of this section to determine whether you exceed a threshold in paragraphs (e) and (f) of this section.

(6) If information is readily available to conclude that the possible defects identified in paragraph (b)(1) of this section are actual defects, count these toward the reporting thresholds in paragraph (f) of this section.

(7) During an investigation, use appropriate statistical methods to project defect rates for engines that you are not otherwise able to evaluate. For example, if 75 percent of the components replaced under warranty are available for evaluation, it would be appropriate to extrapolate known information on failure rates to the components that are unavailable for evaluation. Take steps as necessary to prevent bias in sampled data. Make adjusted calculations to take into account any bias that may remain.

(h) *Investigation reports.* Once you trigger an investigation threshold under paragraph (e) of this section, you must report your progress and conclusions. In your reports, include the information specified in paragraph (d) of this section, or explain why the information is not relevant. Send us the following reports:

(1) While you are investigating, send us mid-year and end-of-year reports to describe the methods you are using and the status of the investigation. Send these status reports no later than June 30 and December 31 of each year.

(2) If you find that the number of components or systems with an emission-related defect exceeds a threshold specified in paragraph (f) of this section, send us a report describing your findings within 21 days after the date you reach this conclusion.

(3) If you find that the number of components or systems with an emission-related defect does not exceed any of the thresholds specified in paragraph (f) of this section, send us a final report supporting this conclusion. For example, you may exclude warranty claims that resulted from misdiagnosis and you may exclude defects caused by improper maintenance, improper use, or misfueling. Send this report within 21 days after the date you reach this conclusion.

(i) *Future production.* If you identify a design or manufacturing defect that prevents engines from meeting the requirements of this part, you must correct the defect as soon as possible for future production of engines in every family affected by the defect. This applies without regard to whether you are required to conduct a defect investigation or submit a defect report under this section.

■ 145. Section 1068.505 is amended by revising paragraphs (a) and (e) and adding paragraph (f) to read as follows:

§ 1068.505 How does the recall program work?

(a) If we make a determination that a substantial number of properly maintained and used engines do not conform to the regulations of this chapter during their useful life, you must submit a plan to remedy the nonconformity of your engines. We will notify you of our determination in writing. Our notice will identify the class or category of engines affected and describe how we reached our conclusion. If this happens, you must meet the requirements and follow the instructions in this subpart. You must remedy at your expense noncompliant engines that have been properly maintained and used, as described in § 1068.510(a)(7). You may not transfer this expense to a dealer or equipment manufacturer through a franchise or other agreement.

* * * * *

(e) You may ask us to allow you to conduct your recall differently than specified in this subpart, consistent with section 207(c) of the Act (42 U.S.C. 7541(c)).

(f) You may do a voluntary recall under § 1068.535, unless we have made the determination described in § 1068.535(a).

■ 146. Section 1068.510 is amended by revising paragraph (a)(7) to read as follows:

§ 1068.510 How do I prepare and apply my remedial plan?

(a) * * *

(7) The proper maintenance or use you will specify, if any, as a condition to be eligible for repair under the remedial plan. Describe how these specifications meet the provisions of paragraph (e) of this section. Describe how the owners should show they meet your conditions.

* * * * *

■ 147. Section 1068.530 is amended by revising the introductory text to read as follows:

§ 1068.530 What records must I keep?

We may review your records at any time, so it is important that you keep required information readily available. Keep records associated with your recall campaign for three years after you send the last report we require under § 1068.525(b). Organize and maintain your records as described in this section.

* * * * *

■ 148. Appendix I to part 1068 is amended by removing paragraph IV and revising the introductory text to read as follows:

Appendix I to Part 1068—Emission-Related Components

This appendix specifies emission-related components that we refer to for describing such things as emission-related warranty or requirements related to rebuilding engines.

[FR Doc. 04–11293 Filed 6–28–04; 8:45 am]

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Tuesday,

June 29, 2004

Part III

Environmental Protection Agency

40 CFR Parts 92 and 94

Control of Emissions of Air Pollution From New Locomotive Engines and New Marine Compression-Ignition Engines Less than 30 Liters per Cylinder; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 92 and 94

[OAR–2003–0190; FRL–7662–8]

RIN 2060–AM06

Control of Emissions of Air Pollution From New Locomotive Engines and New Marine Compression-Ignition Engines Less Than 30 Liters per Cylinder

AGENCY: Environmental Protection Agency (EPA).

ACTION: Advance notice of proposed rulemaking.

SUMMARY: EPA is issuing this Advance Notice of Proposed Rulemaking (ANPRM) to invite comment from all interested parties on our plan to propose new emission standards and other related provisions for new compression-ignition marine engines with per cylinder displacement less than 30 liters and locomotive engines. We are considering standards modeled after our 2007/2010 highway and Tier 4 nonroad diesel engine programs, with an emphasis on achieving large reductions in emissions of particulate matter (PM) and air toxics as early as possible through the use of advanced emission control technology starting as early as 2011. This technology, based on high-efficiency catalytic aftertreatment, is enabled by the availability of clean diesel fuel with sulfur content capped at 15 parts per million. This fuel is already being produced in some U.S. markets, and its availability is expected to become widespread in coming years in response to EPA regulations that require it for an increasingly larger portion of the overall diesel fuel pool, starting with highway fuel in 2006. We are well aware that migrating advanced control technologies to locomotives and marine diesel engines would bring with it a unique set of challenges, but we are hopeful that these can be resolved in a collaborative manner as was done in our highway and nonroad diesel rulemakings.

A program like the one under consideration could result in substantial benefits to public health and welfare through significant reductions in emissions of oxides of nitrogen (NO_X) and particulate matter (PM), as well as hydrocarbons (HC) and air toxics. These pollutants contribute to health problems that include premature mortality, aggravation of respiratory and cardiovascular disease, aggravation of existing asthma, acute respiratory symptoms, chronic bronchitis, and decreased lung function. We believe that diesel exhaust is likely to be carcinogenic to humans by inhalation. Locomotive and marine diesel emissions reductions would particularly benefit those who live, work or recreate in and along our nation's coastal areas, rivers, ports, and rail lines. Such reductions would also have beneficial impacts on visibility impairment and regional haze. We received a substantial number of comments from state and local governments following our proposal last year to set new controls for nonroad diesel emissions, pressing the Agency to adopt similar controls for locomotive and marine diesel engines as quickly as possible.

DATES: Send written comments on this advance notice of proposed rulemaking by August 30, 2004. See **ADDRESSES**, below, for more information about written comments. There will also be opportunity for oral and written comment when we publish our Notice of Proposed Rulemaking for this action.

We expect to publish a Notice of Proposed Rulemaking for this rule by mid-2005 and a Final Rule by mid-2006.

ADDRESSES: Submit your comments, identified by Docket ID No. OAR–2003–0190, by one of the following methods:

- Federal Rulemaking Portal: *http://www.regulations.gov*. Follow the on-line instructions for submitting comments.
- Agency Web site: *http://www.epa.gov/edocket*. EDOCKET, EPA's electronic public docket and comment system, is EPA's preferred method for receiving comments. Follow the on-line instructions for submitting comments.
- E-mail: *locomarine@epa.gov*. Specify docket number OAR–2003–0190 in the body of the message.
- Fax: (202) 260–4400.
- Mail: Environmental Protection Agency, Air Docket, Mailcode 6102T, 1200 Pennsylvania Ave., NW, Washington, DC 20460. Please include a total of 2 two copies.
- Hand Delivery: Environmental Protection Agency, Air Docket, Mailcode 6102T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. OAR–2003–0190. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.epa.gov/edocket*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through EDOCKET, regulations.gov, or e-mail. The EPA EDOCKET and the federal regulations.gov Web sites are "anonymous access" systems, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through EDOCKET or regulations.gov, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket visit EDOCKET on-line or see the **Federal Register** of May 31, 2002 (67 FR 38102). For additional instructions on submitting comments, go to the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available, *i.e.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the EPA Air Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Carol Connell, AANC, U.S. EPA, National Vehicle and Fuels Emission Laboratory, 2565 Plymouth Road, Ann Arbor, MI 48105, (734) 214–4349, Fax: (734)214–4816, *connell.carol@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action Apply to Me?

Locomotive

Entities potentially regulated by this action are those which manufacture, remanufacture and/or import locomotives and/or locomotive engines; and those which own and operate locomotives. Regulated categories and entities include:

Category	NAICS code [a]	Examples of potentially affected entities
Industry	333618, 336510	Manufacturers, remanufacturers and importers of locomotives and locomotive engines.
Industry	482110, 482111, 482112	Railroad owners and operators.
Industry	488210	Engine repair and maintenance.

[a] North American Industry Classification System (NAICS).

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 the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your company is regulated by this action, you should carefully examine the applicability criteria in 40 CFR 92.1, 92.801, 92.901 and 92.1001, as well as 40 CFR 85.1601 and 89.1. If you have questions regarding the applicability of this regulation to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Marine

This proposed action would affect companies and persons that manufacture, sell, or import into the United States new marine compression-ignition engines; companies and persons that make vessels that use such engines; and the owners/operators of such vessels. Further requirements apply to companies and persons that rebuild or maintain these engines. Affected categories and entities include:

Category	NAICS code [a]	Examples of potentially affected entities
Industry	333618	Manufacturers of new marine diesel engines.
Industry	33661 and 346611	Ship and boat building; ship building and repairing.
Industry	811310	Engine repair and maintenance.
Industry	483	Water transportation, freight and passenger.
Industry	336612	Boat building (watercraft not built in shipyards and typically of the type suitable or intended for personal use).

[a] North American Industry Classification System (NAICS).

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 the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your company is regulated by this action, you should carefully examine the applicability criteria in 40 CFR 94.1, as well as the future proposed regulations. Note that in addition to the marine diesel engines currently regulated under 40 CFR 94, this rule also applies to marine diesel engines below 37 kW. If you have questions regarding the applicability of this regulation to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What Should I Consider As I Prepare My Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through EDOCKET, regulations.gov or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

i. Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns, and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Additional Information About This Rulemaking

Locomotive. The current emission standards for new locomotive engines were adopted by EPA in 1998 (*see* 63 FR 18978, April 16, 1998). This advance notice of proposed rulemaking relies in part on information that was obtained for that rule, which can be found in Public Docket A–94–31. That docket is incorporated by reference into the docket for this action, OAR–2003–0190.

Marine. The current emission standards for new marine diesel engines were adopted in 1999 and 2003 (*see* 64 FR 73300, December 29, 1999 and 66 FR 9746, February 28, 2003). This advance notice of proposed rulemaking relies in part on information that was obtained for those rules, which can be found in Public Dockets A–97–50 and A–2000–01. Those dockets are incorporated by reference into the docket for this action, OAR–2003–0190.

Other Dockets. This advance notice of proposed rulemaking relies in part on information that was obtained for our recent highway diesel and nonroad diesel rulemakings, which can be found in Public Dockets A–99–06 and A–2001–28 (*see* also OAR 2003–0012).[1] Those dockets are incorporated by reference into the docket for this action, OAR–2003–0190.

Table of Contents

I. Overview

In recent years, EPA has adopted major new programs designed to reduce emissions from diesel engines. When fully phased in, these new programs for highway and nonroad diesel engines will lead to the elimination of over 90% of harmful pollutants from these sources.[2] The public health and welfare benefits of these actions are very significant, projected at over $70 billion and $83 billion for our highway and nonroad diesel programs, respectively, in 2030. In contrast, the corresponding annual cost of these programs will be a small fraction of this amount. We have estimated the annual cost at $4.2 billion and $2 billion, respectively in 2030. These programs are being implemented over the next decade.[3]

Marine diesel engines less than 30 liters per cylinder (marine diesel engines) and locomotives are significant contributors to our national mobile source emissions inventory.[4,5] Even with recent emission standards for these sectors, the contribution of these engines is expected to grow. Without new controls, we estimate that their respective contributions to mobile source NO_X and fine diesel particulate matter ($PM_{2.5}$) emissions will increase to 27 percent and 45 percent by 2030. Reducing emissions from these two engine categories can lead to significant public health benefits such as reduced premature mortalities and decreased incidences of heart attacks and asthma exacerbations. It will help states and localities attain and maintain PM and ozone national ambient air quality standards (NAAQS).

Locomotive and marine diesel engines are currently subject to emission standards that rely on engine-based technologies to reduce emissions.[6] The opportunity to gain large additional public health benefits, as well as the similarities between these engines and highway and general nonroad engines, lead us to consider additional emission controls based on the same advanced emission control technologies on which our 2007/2010 highway and Tier 4 nonroad diesel engine programs are based. The use of these technologies on locomotive and marine diesel engines will be enabled by the ultra low sulfur diesel (ULSD) requirements established in our recently adopted nonroad diesel rule, which sets a 15 parts per million (ppm) sulfur limit for locomotive and marine diesel fuel beginning in 2012.

In this Advance Notice of Proposed Rulemaking (ANPRM), we describe the emission controls we are considering for locomotive and marine diesel engines. The remainder of this Introduction provides a summary of the controls we are considering and a brief description of the impacts of these emissions on human health and welfare. Sections II and III describe the emission controls we are considering for our locomotive and marine diesel engine programs, respectively. In Section IV, we describe the contribution of these engines to mobile source NO_X and diesel $PM_{2.5}$ inventories and our plans for our future cost analysis. Section V contains our plan to solicit the input from small businesses in these sectors. Finally, sections VI and VII contain information about public participation and statutory and executive order review. We are interested in comments covering all aspects of this ANPRM.

We are planning to issue a Notice of Proposed Rulemaking addressing engine standards for locomotive and marine diesel engines by mid-2005, with a final rule targeted for mid-2006.

A. What New Controls Is EPA Considering?

EPA currently has emission standards for locomotives and marine diesel engines. The standards for new locomotives, adopted in 1998, phase in from 2000 through 2005. That program includes emission limits (that apply upon remanufacturing) for existing locomotives that were originally manufactured after 1973. The standards for marine diesel engines were adopted in 1999 for commercial marine engines

[1] Control of air pollution from new motor vehicles: Heavy-duty engine and vehicle standards and highway diesel fuel sulfur control requirements, 66 FR 5001 (January 18, 2001); Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, published elsewhere in this issue of the **Federal Register**.

[2] As used in this ANPRM, "nonroad diesel engines" refers to the off-highway engines regulated under 40 CFR Part 89 (Tier 1, 2, and 3 standards) and Part 1039 (Tier 4). This generally covers a wide variety of land-based engines, including those used in farm, construction, industrial, and mining applications.

[3] *See* 66 FR 5001 (January 18, 2001), and the Nonroad final rule published elsewhere in this issue of the **Federal Register** for the final rules regarding highway diesel, and nonroad diesel programs, respectively.

[4] As used in this ANPRM, "marine diesel engine" refers to compression-ignition marine engines below 30 liters per cylinder displacement unless otherwise indicated.

[5] This rule will address emissions from all marine diesel engines below 30 liters used for commercial, recreational, or auxiliary applications. Marine diesel engines at or above 30 liters per cylinder are not part of this rulemaking. These large engines, which are used for propulsion on ocean-going vessels, are the largest mobile source diesel engines regulated by EPA. They will be addressed in a rule to be finalized by April 27, 2007. *See* 68 FR 9746 (February 28, 2003) for more information about that future rule.

[6] *See* the "Additional Information about this Rulemaking" section above for the specific cites.

and in 2002 for recreational marine engines. They phase in from 2004 through 2009, depending on engine size and application. These locomotive and marine diesel engine standards are similar in stringency to our nonroad Tier 2 standards that were set in 1998 and began phasing in starting in 2001. The technologies needed to meet our nonroad diesel Tier 2 standards in turn are derived from highway diesel engine technologies that have been in widespread use since the early 1990's, which achieve emissions reductions through judicious in-cylinder control of ignition timing and fuel injection pressure. The significant lag in leadtime between application of this technology to land-based and marine nonroad engines compared to highway engines is more reflective of the challenges involved in regulating markets just starting to focus on emissions control programs (including development of testing lab capability and production line quality assurance measures, and the like), than of the challenges involved in adapting the technology itself to the differing engine applications.

Emission control technologies for diesel engines have advanced substantially since these rules were issued, especially with regard to high-efficiency catalytic exhaust emission control systems. Our 2007 highway and Tier 4 nonroad diesel engine emission standards are predicated on these new technologies enabling NO_X, HC and PM emission reductions of 90 percent or more. These new standards apply to engines ranging up to several thousand horsepower. PM and HC emissions can be controlled to these levels through the use of catalyzed diesel particulate filters (CDPFs). CDPFs are a well proven technology and have been used in numerous retrofit applications including retrofits of locomotive switcher engines. NO_X emissions can be controlled through the use of NO_X adsorbers or selective catalytic reduction (SCR), both of which are capable of large NO_X reductions. SCR technology has already been implemented on a number of marine engines.[7] To operate reliably and at high efficiencies, these technologies require very low sulfur levels in diesel fuel. We have already put programs in place that will reduce sulfur to 15 ppm for highway and nonroad diesel fuel. Our nonroad diesel fuel program applies the 15 ppm fuel sulfur cap to refiners and importers of locomotive and marine diesel fuel beginning in 2012. However, the widespread availability of 15 ppm sulfur diesel fuel throughout the country even before this date makes it viable to consider locomotive and marine engine programs as early as 2011 that are based at least in some part on the use of this fuel.

In ways relevant to the use of advanced emissions control technologies, marine diesel engines and locomotives are similar to highway and nonroad diesel engines. In fact, many marine diesel engines are derivatives of land-based nonroad engines, and both marine and locomotive engines share important design features with highway and nonroad diesel engines. The nonroad diesel standards cover engines of all sizes, including small engines similar in size to the smallest auxiliary marine engines and large engines on the scale of locomotive and large marine propulsion engines. The new catalyst based emission control technologies, which are expected to be applied for highway and nonroad diesel engines, can be similarly effective at controlling emissions from locomotive and marine engines. Therefore, we believe it is appropriate to consider applying advanced aftertreatment standards to locomotives and marine engines as well. Despite the fundamental similarities involved, we recognize that there are also some differences between the highway/nonroad engines for which the technologies were initially designed and the locomotive/marine engines to which we are considering applying this technology, and this may present some special challenges. We discuss these in this section I.A below. However, we do not believe that these challenges are so significant as to pose a barrier to setting standards based on implementing these technologies in the future. We do recognize that in order to address potential issues, we may need to consider flexibility in how the standards are implemented, and we request comment on the technology issues listed here and on any other technology issues that we should consider in setting new standards.

Potential issues unique to locomotives include available space for the technology and scaling up of aftertreatment systems to large horsepower sizes. When scaled to locomotive-sized engines, the kinds of aftertreatment systems being developed for highway diesel engines would logically be larger, though not necessarily much larger than systems that will be applied to large nonroad diesels. Total locomotive size is constrained by the existing infrastructure. Height and width are constrained by tunnel and bridge clearances, and length is constrained by the curvature of the rails. On the other hand, we believe the use of aftertreatment may make it possible to reduce the need for the additional radiator space that is currently being applied to locomotives to increase aftercooling capacity. We request comment on the significance of any space constraints regarding the use of aftertreatment on locomotives, as well as potential ways of dealing with such constraints.

Exhaust temperature may also be a key factor in the proper design of emission control technologies for locomotive and marine applications. For most catalytic emission control technologies there is a minimum temperature below which the rate of chemical reactions necessary for emissions control falls off. In general, exhaust temperature increases with engine power and can vary dramatically as engine power demands vary. Prolonged low-power operation can hamper the overall effectiveness of catalyst-based aftertreatment devices, unless steps are taken in designing them to compensate. An example of an application with a lot of low-power operation would be a tug boat that primarily idles or operates at low light loads moving around the harbor and only at high loads for a short time when pushing ships. We believe it may be necessary for advanced exhaust emission controls in at least some locomotive and marine applications to use active regeneration mechanisms, such as the post-injection of diesel fuel into the exhaust stream to initiate thermal transients. This would be similar to the design measures we are projecting for robust operation of nonroad diesel engines in our Tier 4 program. We request comment on exhaust temperature profiles for locomotive and marine diesel engines and their impact on aftertreatment design strategies.

One special consideration for marine engines derives from the fact that their exhaust systems are typically designed to operate with surface temperatures below 100°C. This is intended to minimize the risk of fires in response to Coast Guard safety requirements. For most commercial marine engines, the exhaust piping is insulated and the exhaust is routed either through a muffler or under water. Typically, for larger vessels, the exhaust exits above the top of the vessel. However, in many recreational and light-duty commercial applications, the exhaust is water-jacketed and leaves the vessel below the water surface. In some cases, the jacketing-water and exhaust are mixed in the exhaust system before exiting the

[7] *See* EPA docket items OAR–2003–0190–0002, 0003, 0004, and 0005.

vessel. This is especially common in sterndrive applications where the jacket-water mixes with exhaust within feet of the cylinder exhaust port and exits through the lower drive unit.

Exhaust systems that rely on insulation to control surface temperature are likely to prove to be very well matched to the new emission control technologies which can benefit from such a thermal management technique. However, the use of water-jacketing may raise additional issues to be addressed. The first issue is the effect of the water jacketing on the exhaust gas temperature. Where an insulated exhaust helps keep the heat in the exhaust, water-jacketing removes heat thus lowering average exhaust temperatures and potentially reducing catalyst system effectiveness. We believe that there are a number of solutions to this issue including close-coupling of the catalyst system and the use of an insulating gap between the exhaust flow and the water jacket similar to the approach used to insulate the exhaust system. For sterndrive applications or other applications where the exhaust is mixed with the water, we believe it may be necessary to redesign the exhaust system to ensure there is enough room in the dry part of the exhaust system to package the aftertreatment system. We request comment on packaging constraints for marine diesel engine applications that would affect the feasibility of applying exhaust aftertreatment or other emission control strategies. We also request comments describing methods to address potential issues related to system packaging.

We believe that, given adequate development lead time and appropriate structuring of phase-in provisions, locomotive and marine diesel engines could be designed to successfully employ the same high-efficiency exhaust emission control technologies now being developed for highway and nonroad engine use.

B. Why Is EPA Considering New Controls?

Marine diesel engines and locomotives contribute to a number of serious air pollution problems and will continue to do so in the future absent further emission reduction measures. Their emissions lead to adverse health and welfare effects associated with ozone, PM, NO_X, and volatile organic compounds, including toxic compounds. In addition, diesel exhaust is of specific concern because it is likely carcinogenic for humans as well as posing a hazard from noncancer respiratory effects. Ozone, NO_X, and PM also cause significant public welfare harm such as damage to crops, eutrophication, regional haze, and soiling of building materials.[8]

Millions of Americans continue to live in areas with unhealthy air quality that may endanger public health and welfare. Part or all of 474 counties nationwide are in nonattainment for either failing to meet the 8-hour ozone standard or for contributing to poor air quality in a nearby area. There are approximately 159 million people living in these non-attainment areas. In addition, approximately 65 million people live in counties where air quality measurements violate the $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). These numbers do not include the tens of millions of people living in areas where there is a significant future risk of failing to maintain or achieve the ozone or $PM_{2.5}$ NAAQS. Federal, state, and local governments are working to bring ozone and PM levels into compliance with the NAAQS attainment and maintenance plans and the reductions we are considering in this ANPRM will play a critical part in these actions. In the comments submitted on our recent nonroad diesel rule, several states requested EPA take action to control these emissions. For example, Illinois Lieutenant Governor Pat Quinn commented that "in Illinois locomotives are quite prevalent especially in the urban area in and around Chicago. It is in urban areas that the risk of cancer and asthma is highest. Incorporating marine vessels and locomotives into the regulations will create an incentive to aggressively advance technology." [9] Marianne L. Horinko, Acting Administrator, California Air Resources Board, commented that "in 2000, locomotives and commercial marine engines were responsible for 15 percent of the PM emissions inventory for diesel mobile sources in California * * * ARB strongly recommends that U.S. EPA proceed as rapidly as possible * * * to establish aftertreatement-based emissions standards for locomotive and marine engines." [10] Dr. Pamela M. Berger, Director of Environmental Policy, Office of the Mayor, City of Houston commented that "given that municipalities and states are not empowered to regulate locomotives and that these vehicles are a growing source of emissions, we would encourage EPA to regulate them." [11] Many other commenters encouraged the Agency to adopt further emission controls for these engines as quickly as possible. See section 8.3.3 of the Summary and Analysis of Comments document for the nonroad diesel final rule, available in EPA docket A–2001–28.

Even with the control measures already in place for locomotives and marine diesel engines, the combination of expected future growth and the dramatic emission reductions expected from our recently established highway and nonroad diesel engine control programs will make the relative emission contribution from locomotives and marine diesel engines grow quite large over time. We estimate that they will contribute about 27 percent and 45 percent of national mobile source NO_X and diesel $PM_{2.5}$ emissions, respectively, by 2030. Additionally, the contribution of these engines can be significantly higher in ports, in rail centers, and along coasts and railways. Many of these areas are highly populated and suffer from poor air quality. Because locomotives and marine diesel engines contribute greatly to these air quality problems, further controls in this source category will likely be needed to resolve them. Commenters are encouraged to provide any information they may have that would help us to further assess the contributions of locomotive and marine engines to the nation's air quality problems, especially in regard to future growth in these markets.

We expect that our proposal for new control measures will focus on PM and air toxics reductions as early as feasible, consistent with our 2007/2010 highway and Tier 4 nonroad rules. However, we recognize that these engines are also significant contributors of NO_X emissions and that high-efficiency NO_X controls may well be feasible for these engines in the timeframes under consideration. We request comment, therefore, on all aspects of potential emissions control measures that might be taken to improve air quality.

C. Basis for Action Under the Clean Air Act

Section 213 of the Clean Air Act (the Act) gives us the authority to establish emissions standards for nonroad engines and vehicles. Section 213(a)(3) authorizes the Administrator to set (and from time to time revise) standards for

[8] For a full discussion of the human health and environmental problems that diesel engine emissions contribute to, see Chapter 2 of the Regulatory Impact Analysis for our nonroad diesel rule, available on our Web site: *http://www.epa.gov/otaq*.

[9] Air Docket OAR 2003–0012, Comment OAR–2003–0012–0781.

[10] Air Docket OAR 2003–0012, Comment OAR–2003–0012–0644.

[11] Air Docket OAR 2003–0012, Comment OAR–2003–0012–0630.

NO_X, VOCs, or carbon monoxide emissions from nonroad engines, to reduce ambient levels of ozone and carbon monoxide. That section specifies that the "standards shall achieve the greatest degree of emission reduction achievable through the application of technology which the Administrator determines will be available for the engines or vehicles." As part of this determination, the Administrator must give appropriate consideration to cost, lead time, noise, energy, and safety factors associated with the application of such technology. Section 213(a)(4) authorizes the Administrator to establish standards to control emissions of pollutants, such as PM, which "may reasonably be anticipated to endanger public health and welfare." In setting appropriate standards, EPA is instructed to take into account costs, noise, safety, and energy factors. Section 213(a)(5) contains similar provisions that authorize the Administrator to set standards for new locomotive engines.

As part of the development of our Notice of Proposed Rulemaking, we will analyze whether the emission control program under consideration for locomotive and marine diesel engines is technologically feasible and reflects the greatest degree of emission reduction achievable in the model years to which it would apply, giving appropriate consideration to costs and the other factors listed in the statute. We will also perform an analysis of the impacts of locomotive and marine diesel emissions on human health and welfare and the anticipated benefits of the standards.

II. Controlling Locomotive Emissions

A. Background

1. What Is the Nature of the Locomotive Market?

There are currently three manufacturers of locomotive engines for the U.S. market: General Electric (GE), the Electromotive Division of General Motors (EMD), and Caterpillar. Total sales of freshly manufactured locomotives in the U.S. can vary dramatically from year to year. Since 1997 sales have been between 600 and 900 units per year. All freshly manufactured locomotives are essentially built to order for the major Class I railroads. Class II and III railroads typically purchase used locomotives rather than purchasing new.[12]

Locomotives are typically remanufactured to "as new" condition every five to seven years throughout their services lives, and they typically remain in service for 30 to 40 years or more before being scrapped. Under our current regulations, these remanufactured engines are considered "new" for the purposes of applying emissions standards. As might be expected, there is a thriving market in both aftermarket parts and remanufacturing services. While some railroads remanufacture their own locomotives, other railroads contract to have this work performed for them. The two largest locomotive manufacturers (GE and EMD) both have unit exchange programs where a railroad can trade in a locomotive engine in need of remanufacture for one that has just been remanufactured. There are also a number of independent companies that offer engine remanufacturing services.

2. What Are the Existing Standards for Locomotives?

Three separate sets of emission standards have been adopted, with applicability of the standards dependent on the date a locomotive is freshly manufactured.[13]

- *Tier 0* standards apply to locomotives and locomotive engines that were freshly manufactured from 1973 through 2001; the standards apply any time the engines are manufactured or remanufactured.
- *Tier 1* standards apply to locomotives and locomotive engines that are freshly manufactured from 2002 through 2004. These locomotives and locomotive engines will be required to meet the Tier 1 standards at the time of original manufacture and at each subsequent remanufacture.
- *Tier 2* standards apply to locomotives and locomotive engines that are freshly manufactured in 2005 and later. These locomotives and locomotive engines will be required to meet the applicable Tier 2 standards at the time of original manufacture and at each subsequent remanufacture.

We also have opacity standards for these locomotives and locomotive engines. Electric locomotives, historic steam-powered locomotives, and locomotives freshly manufactured before 1973 are not currently covered by emission regulations.

When fully phased in, these emission standards will reduce NO_X emissions from locomotives by nearly two-thirds, and HC and PM emissions by half. Nevertheless, even with these standards in place, serious concerns about emissions from locomotives remain, as discussed in section I.B.

B. Scope

Because of the potential for locomotives to remain in service for 40 years or more as discussed in section II.A.1, we are considering additional requirements for all 1973 and later locomotives. We are considering an approach similar to our existing program, in which we would set new standards for in-use and new engines, grouped into three categories:

- Locomotives freshly manufactured after the effective date of new Tier 3 standards.
- Locomotives currently subject to the Tier 2 standards.
- Locomotives currently subject to the Tier 0 and Tier 1 standards.

For the first group of engines, those that would be freshly manufactured after the new standards begin to take effect (as early as 2011), we are considering standards that reflect the use of advanced emission controls and aftertreatment devices. These potential standards are discussed in Section II.C. Regarding the second group of engines, we note that manufacturers have already finished the primary design process for their Tier 2 locomotives and are currently testing these designs to ensure that they will be ready for production by 2005, and this will be taken into account in evaluating ideas for further control measures for these engines.

We are also considering new requirements for locomotives freshly manufactured in model years 1973 through 2004, currently subject to Tier 0 or Tier 1 standards. In addition to potential new standards for some or all of these engines upon remanufacture, we are interested in ideas for voluntary provisions and initiatives that could encourage cleaner engines, and in how these might be coordinated with new standards for new and remanufactured engines through emissions trading, fleetwide average standards, or similar approaches. Also, we request comment on the applicability of technologies being developed for Tier 2 locomotives to these earlier engines upon remanufacture.

C. Tier 3 Standards and Effective Dates

1. Tier 3 Standards for New Engines

We are considering emission standards for new locomotives built as

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[12] In the United States, freight railroads are subdivided into three classes by the Federal Surface Transportation Board (STB), based on annual revenue. In 1994 a railroad was classified as a Class I railroad if annual revenue was $250 million or greater ($1991), as a Class II railroad with annual revenue of at least $20 million but less than $250 million ($1991), and as a Class III railroad with revenues below $20 million (1991). Surface Transportation Board 1996/1997 Annual Report, accessed at *http://www.stb.dot.gov/stb/docs/ActivityReport1996–1997.pdf* on April 6, 2004.

[13] 63 FR 18977 (April 16, 1998).

early as 2011, based on the application of advanced emission control technologies. These technologies are currently being developed for use in highway and nonroad applications and will begin to see widespread use in these applications starting in 2007. In those programs, we estimated that NO_X and PM emissions could be reduced by 90 percent or more from emission levels in the exhaust leaving the engine through the use of NO_X aftertreatment and PM filter technologies. We would expect that similar levels of NO_X and PM reductions could be achieved by applying these technologies to locomotives as well.

Although for the most part these highway and nonroad engines are smaller than locomotive engines, much of the fundamental diesel engine and emission control technology involved is the same, such as PM filtering matrix designs, catalyst formulations to optimize exhaust stream chemical reactions, and mechanisms for active regeneration of filter and adsorber beds. Furthermore, some nonroad diesel engines subject to our nonroad Tier 4 regulations starting in 2011 are of similar size to locomotive engines, 1000 to 3000 horsepower or more. Although they are not typically made by the same manufacturers, locomotive engines have substantial design and operating similarities to large mobile generator set engines that will allow the locomotive engines to benefit from emission control technology being developed for (and in limited applications already applied to) these generator sets. We note too that the largest generator sets, those over 1200 hp, are subject to the earliest stringent NO_X control requirements of any engines in the Tier 4 program, 0.50 g/bhp-hr in 2011, and to stringent PM standards in that year as well.

Given that other technologies, such as exhaust gas recirculation (EGR) and optimized fuel injection, could also be applied in tandem with exhaust aftertreatment, we expect that similar final emission levels to those achievable from highway and nonroad engines may be feasible. The availability of EGR and other engine-based means of achieving some degree of emissions control also introduces the potential for Tier 3 control in multiple phases, as we do not expect locomotive manufacturers will need to use EGR to meet the Tier 2 standards in 2005. As a result, we request comment on the different forms these future standards could take, including the following:

- Should we adopt the approach taken in the heavy-duty highway and nonroad diesel programs involving a PM control requirement on 100% of the engines concurrent with a NO_X requirement that is phased in over three years, starting as early as 2011?
- Would it be more appropriate for locomotive manufacturers to focus their technology development efforts on a single, final tier of standards with the possibility of getting to aftertreatment-based emission levels sooner than would likely be the case under the two-phase approach?
- Are there phase-in options that we could adopt to encourage the early introduction of aftertreatment technology?
- How should aftertreatment-based particulate matter controls be coordinated with those for NO_X?

2. Idling Emissions Control

Locomotives typically spend significant amounts of time idling. This is especially the case in switchyards, which tend to be located in urban areas. Our current test procedure reflects this reality, with idling operation representing 38 percent of the line-haul duty cycle and almost 60 percent of the switch duty cycle. Although the fact that idling emissions per unit time may be relatively low considering that they occur at low power and fuel consumption levels, the high percentage of total time locomotives spend idling in urban areas, some of which are hot-spot air quality problem areas, may warrant our addressing these emissions, and we request comment on our doing so.

We note that locomotive operators already recognize that there is some public demand to reduce the idling of locomotives. For this reason some railroads are beginning to employ idle shutdown technology on locomotives. This technology simply shuts down a locomotive after a certain length of time at idle conditions. Clearly this technology is feasible and available for use, and we are considering what steps we might take to encourage or require its widespread use. Thus, we request comment on whether we should consider the mandatory use of idle shutdown technology or whether a voluntary program would be more appropriate, both for new and in-use locomotives. In the case of a voluntary program, we request comment on any incentives we might offer to encourage participation in such a program.

D. Testing

In use, locomotive engines are operated at a series of discrete load and speed points, called notches. Our current test procedure involves running a locomotive or locomotive engine through all of its different power notches, as well as its idle settings. Emissions are measured at each of these steady state points, and compliance with the applicable emission standards is determined by weighting the emissions at each point according to the applicable weighting factors to arrive at a composite emissions level. These weighting factors were derived through the analysis of in-use operating data from a number of locomotives, and we believe they accurately represent in-use locomotive operations.

Because of this, we do not expect it will be necessary to adopt comprehensive "not-to-exceed" standards provisions for locomotives as we have in our highway and nonroad diesel engine programs. However, the possible inclusion of exhaust aftertreatment technology on future locomotives leads us to request comment on whether the simple approach of weighting the steady state modes according to the duty cycle would still accurately represent in-use operation. Exhaust temperatures tend to be lower at the lower power notches and idle modes, raising questions regarding the effectiveness of aftertreatment technology in those modes of the test procedure versus those modes in actual operation, given that the test procedure requires operating parameters to stabilize in each mode before emissions sampling begins.

The test duty cycle weightings are based on the average amount of time that a locomotive spends in each power notch over a period of time. However, it does not address whether the time spent in lower power notches happens in fewer, longer segments or many shorter ones. If the actual in-use operation in low power notches happens in fewer, longer segments, the test cycle would be more representative of actual in-use operation from an exhaust temperature perspective than if the low power notch operation occurred in a higher number of shorter segments, with operation at higher power notches mixed in. In this latter case, the higher power notch operation may serve to keep exhaust temperatures higher in the low power notches than might be the case if the low power notch operation took place in fewer, longer segments. We request comment on whether this is a concern and, if so, what modifications could be made to the test procedures without impacting its viability or representativeness, or the stringency of the standards.

E. Certification and Compliance

Our current locomotive compliance program contains provisions for engine family certification, production line testing and in-use testing of both freshly manufactured and remanufactured locomotives. The in-use testing program contains requirements for locomotive manufacturers and remanufacturers, as well as for locomotive operators. We are requesting comment on whether we should consider any changes or additions to our current certification and compliance programs. In addition to possible modifications to our current programs, we are asking for comment on whether an onboard diagnostic (OBD) program would be needed for locomotives, especially for locomotives equipped with advanced exhaust aftertreatment devices.

We currently have OBD requirements in place or under development for a number of mobile source programs, including light-duty highway, heavy-duty highway, and nonroad diesel engines. We request comment on the appropriateness and need for a locomotive diagnostic program in light of our current in-use testing programs, and specifically request comment on what types of parameters would be monitored under such a diagnostic program. We are particularly interested in comments on how our existing OBD programs for other source categories could be adapted for use on locomotives.

III. Controlling Marine Diesel Engine Emissions

A. Background

1. What Is the Nature of the Marine Diesel Engine Market?

Our current marine diesel engine emission control program distinguishes between five kinds of marine diesel engines, defined in terms of displacement per cylinder.[14] These five types are set out in Table III–1. In this rulemaking we will consider new standards for all of these marine diesel engines except Category 3 engines. Category 3 marine diesel engines, which are used for propulsion on ocean-going vessels, will be covered in a separate rule to be issued by April 27, 2007.[15]

All of the marine diesel engines that are included in this rule operate on distillate diesel fuel. Some Category 2 marine diesel engines, however, may operate on a blend of distillate and residual fuel or even on residual fuel (for example, fuels commonly known as DMB, DMC, RMA, and RMB).[16] Operation on these higher sulfur fuels may require engine modifications.

We request comment on the extent to which Category 2 marine diesel engines on vessels in the U.S. fleet use residual fuel or residual fuel blends and how we should take this into account as we design the emission control program for those engines.

TABLE III–1.—MARINE DIESEL ENGINE CATEGORIES

Category	Rated power	Displacement per cylinder	Final rule publication
Small	≤37 kW	any	1998
Commercial C1	>37 kW	< 5 liters	1999
Commercial C2	>37 kW	≥ 5 liters and < 30 liters	1999
Commercial C3	>37 kW	≥ 30 liters	2003
Recreational	>37 kW	< 5 liters	2002

The same engine manufacturers that dominate the land-based nonroad engine market are also active in the marine diesel engine market. These manufacturers often make recreational as well as commercial marine diesel engines. Annual sales are different for each of the categories addressed in this rule but are smaller than for their land-based counterparts. According to analysis performed for our 1999 rule, there are about 5,000 commercial C1 engines produced annually, about 100 commercial C2 engines, and about 10,000 recreational diesel engines. In addition, there are about 6,000 marine diesel engines less than 37 kW produced annually. Like locomotives, certain marine diesel engines can have long service periods, with some of the engines remaining in service for as long as 20 or even 30 years.

2. What Are the Existing Standards for Marine Diesel Engines?

Our 1999 rule for commercial marine diesel engines set two tiers of emission limits for Category 1 and Category 2 marine diesel engines (*see* 40 CFR 94.9). The Tier 1 standards were initially adopted as voluntary standards and are equivalent to the MARPOL Annex VI NO_X limits.[17] These standards were made mandatory for engines above 2.5 liters per cylinder in our 2003 rule, beginning in 2004. The Tier 2 commercial marine diesel engine standards we adopted in 1999 address NO_X, PM, HC, and carbon monoxide emissions, and go into effect from 2004 through 2007, depending on engine size. At the time, we estimated that these standards would yield a 27 percent reduction in NO_X emissions from the MARPOL Annex VI NO_X limits and a 26 percent reduction in PM emissions in 2020.

Recreational marine diesel engines were included in our 2002 recreational vehicle rule (*see* 40 CFR 94.9). These engines are subject to standards that are equivalent to our commercial marine diesel engine standards, but two years later.[18] We estimated that these standards would yield a 21 percent reduction in NO_X emissions and an18 percent reduction in PM emissions in 2020.

Marine diesel engines below 37 kW were included in our 1998 nonroad diesel rule and are subject to the same Tier 1 and Tier 2 standards as their land-based counterparts (*see* 40 CFR 89.112).[19] They were not included in our most recent diesel nonroad rule, however, and are therefore not subject

[14] This approach was used because per-cylinder displacement is an engine characteristic that is not easily changed and is constant for a given engine model or series of engine models. It therefore avoids the problem that can arise when a higher power engine is made by joining together more cylinders; the larger version of the engine could be subject to a different numerical standard than an engine formed from a smaller number of cylinders.

[15] *See* 68 FR 9746 (February 28, 2003) for more information about the future rule for Category 3 marine diesel engines.

[16] The final rule setting limits on the sulfur content of marine diesel fuel does not apply to distillate fuel with a T90 greater than 700°F that is used only in Category 2 or Category 3 marine diesel engines. This would include marine DMB and DMC fuels used in these engines.

[17] The MARPOL Annex VI NO_X limits are the engine standards adopted by the International Maritime Organization in Annex VI to the International Convention on the Prevention of Pollution from Ships, 1973, as Amended by the 1978 Protocol Relating Thereto. These international consensus standards will go into effect when the Annex has been ratified by 15 countries representing no less than 50 percent of the world's merchant shipping tonnage. To date, the Annex has been ratified by 13 countries representing about 54.5 percent. For more information on MARPOL Annex VI, see our 2003 rule.

[18] 67 FR 68242 (November 8, 2002).

[19] 63 FR 56967 (October 23, 1998).

to the subsequent tier of standards that will apply to their land-based counterparts. Instead, additional controls for small marine diesel engines were deferred to this rulemaking.

B. Scope

The emission control program contemplated by today's action is intended to cover all new marine diesel engines up to 30 liters per cylinder, including those used in commercial, recreational, and auxiliary applications.

EPA's existing standards for new marine diesel engines do not apply to engines that were built prior to the effective date of those standards. In our 1998 proposal, we requested comment on whether we should apply the standards to engines when they are remanufactured, using the locomotive approach, given the long useful lives of marine diesel engines. Under the locomotive approach, an engine built in 1973 or later but prior to entry into force of the Tier 1 standards is considered to be "new" when each of its power assemblies is replaced or is inspected and qualified. This approach was used to address the long periods of service commonly found for locomotives (30 to 40 years). Certain commercial marine diesel engines also have long periods of service (20 to 30 years) that retard the turnover to the new standards. However, several characteristics of the marine industry make a direct application of this approach to marine diesel engines more difficult. Unlike the railroad industry, there are many companies that operate marine diesel engines, and these companies do not rely on a small number of engine remanufacturers to work on their engines. In fact, many of these operators employ their own mechanics to do all maintenance and remanufacturing work. There is accordingly little uniformity in remanufacturing practices across the industry. In addition, setting emission limits for remanufactured in-use marine diesel engines may be disruptive to a large number of small businesses that own and operate these vessels.

We are interested in exploring this issue, especially with regard to other mechanisms that could be used to achieve additional reductions from in-use engines. In particular, we request comment on how we could design such a program in the context of the remanufacturers' specific market characteristics to provide incentives that encourage retrofits or that accelerate turnover. We request comment on the feasibility and potential costs and benefits of both voluntary and mandatory remanufacturing provisions for in-use marine diesel engines.

C. Tier 3 Standards and Effective Dates

Substantial progress has been made in recent years in controlling diesel exhaust emissions through the use of robust, high-efficiency catalytic devices placed in the exhaust system.[20, 21] Similar to the discussion above regarding technologies for PM, HC, and NO_X control for locomotives, we believe PM filters and NO_X adsorbers can be applied to marine diesel engines for emission reductions of 90% or more. For more specific information on these technologies, the regulatory impact analyses for our 2007 highway diesel program and most recent nonroad rule contains extensive discussions of how these devices work, how effective they are at reducing emissions, and what their limitations are, particularly their dependence on very-low sulfur diesel fuel to function properly.[22, 23]

Although there are important differences between land-based and marine diesel engines, they are fundamentally similar. The majority of marine diesel engine designs are derived from highway and nonroad engine platforms. In addition, engines in some nonroad diesel applications, such as underground mining, have water-cooled exhaust systems similar to those used in many marine applications. Manufacturers of underground mining equipment have pioneered the use of advanced aftertreatment technologies for many years. We request comment on the similarities and differences between land-based and marine diesel engines with respect to emission control. We also request comment on whether marine diesel engines can be designed to successfully employ the same high-efficiency exhaust emission control technologies now being developed for highway and nonroad use. Commenters should consider the anticipated availability of diesel fuel meeting the 15 ppm maximum sulfur requirement and the required amount of development lead time.

We request comment on emission standards for marine diesel engines that would be based on the transfer of exhaust emission control technology from land-based diesel engines. This approach would be consistent with the current marine Tier 2 emission standards which were based on technology transfer from land-based Tier 2 engines. We are considering applying such emission standards to new marine diesel engines built as early as 2011. Similar to the locomotive standards described in Section II above, we request comment on the following:

- Whether we should adopt the approach taken in the heavy-duty highway and nonroad diesel programs involving a PM control requirement on 100% of the engines concurrent with a NO_X requirement that is phased in over three years;
- Whether it would be more appropriate for marine engine manufacturers to focus their technology development efforts on a single, final tier of standards with the possibility of getting to aftertreatment-based emission levels sooner;
- Whether there are phase-in options that we could adopt to encourage the early introduction of aftertreatment technology; and
- How aftertreatment-based particulate matter controls should be coordinated with those for NO_X.

The technologies used to meet the Tier 2 standards are primarily in-cylinder engine controls such as fuel and air management improvements, consistent with the approach taken for heavy-duty highway diesel engines in the 1990's and subsequently for the nonroad diesel engine Tier 2 standards. Due to differences in engine design and application, the marine Tier 2 standards for $HC+NO_X$ are slightly higher than those in the nonroad Tier 2 standards. We request comment of whether these differences in design and application could have an effect on the levels of aftertreatment-based standards.

We recognize that marine diesel engines generally have a much wider band of power ratings for a given per-cylinder displacement, however, we request comment on whether or not we should continue to catagorize the engines based on specific displacement rather than by rated power. The new nonroad Tier 4 standards established key aftertreatment-based emission control standard divisions at 19 kW and 56 kW engine power ratings. We request comment on whether these (or equivalent per-cylinder displacement

[20] "Highway Diesel Progress Review," U.S. EPA, June 2002. EPA420–R–02–016. (*www.epa.gov/air/caaac/dieselreview.pdf*) and "Highway Diesel Progress Review Report 2," U.S. EPA, March 2004, EPA420–R–04–004 (*http://www.epa.gov/otaq/regs/hd2007/420r04004.pdf*).

[21] "Meeting Technology Challenges For the 2007 Heavy-Duty Highway Diesel Rule", Final Report of the Clean Diesel Independent Review Subcommittee, Clean Air Act Advisory Committee, October 30, 2002. (*www.epa.gov/air/caaac/diesel/finalcdirpreport103002.pdf*).

[22] "Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements," U.S. Environmental Protection Agency, EPA420–R–00–026, December 2000. This document is available on our Web site at *http://www.epa.gov/otaq/diesel.htm*.

[23] "Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines," U.S. Environmental Protection Agency, EPA 420-R-04-007, May 2004. This document is available on our Web site, *www.epa.gov/otaq*.

categories) would be appropriate for marine engines as well.

D. Testing

1. NTE Zone

The emission standards for marine diesel engines include not-to-exceed requirements in which engines must meet specified emission limits within a zone of engine operation. This NTE zone is supplementary to primary emission standards which are based on the weighted average of emissions measured over a modal duty cycle. The purpose of the NTE requirements is to provide robust control of emissions over a broad range of in-use speed and load combinations (and ambient conditions) that a marine engine may experience in-use.

One issue that has been raised with the use of aftertreatment is its effectiveness at light loads where exhaust temperatures are low. The modal duty cycle for commercial marine engines stresses high load operation, while the duty cycle for recreational marine engines is weighted more towards lighter loads. However, even for commercial marine engines, a large portion of the engine operation for vessels operating in harbors or near ports may be at light load. This operation is important because it is in harbors and ports that the emissions from marine engines may affect the most people. Therefore, an emission control strategy that works well at high loads, but poorly at light loads, may appear effective over the current test procedures without providing significant in-use emission benefits.

We request comment on whether and how the marine diesel engine emissions standards and test procedures should be modified to better consider light load conditions. For instance, we request comment on whether the modal duty cycles should be modified or if the NTE zone would need to be expanded to capture more light load operation. If the NTE zone were adjusted, we request comment on how the emission caps would need to be adjusted to better reflect the capabilities of aftertreatment technology. We also solicit comment on alternative approaches that would help ensure the effectiveness of emission control technology over the wide range of operation and ambient conditions that a marine engine may experience in-use.

2. In-Use Compliance

To sustain the emission benefits over the broadest range of in-use operating conditions, marine diesel engines must meet the applicable emission standards throughout their useful lives. One program that would help achieve this goal is manufacturer-run in-use testing. EPA requests comment on the concepts discussed below.

The Agency plans to promulgate the in-use testing requirements for heavy-duty highway vehicles in the December 2004 time frame and plans to propose a manufacturer-run in-use testing program for nonroad land-based diesel engines by 2005 or earlier. The nonroad diesel engine program is expected to be patterned after the heavy-duty highway program. The Agency expects to pattern the in-use testing requirements for nonroad diesel engines after a program that is being developed for heavy-duty diesel highway vehicles. The highway diesel vehicle program will be funded and conducted by the manufacturers of heavy-duty diesel highway engines with our oversight. We expect it will incorporate a two-year pilot program. The pilot program will allow the Agency and manufacturers to gain the necessary experience with the in-use testing protocols and generation of in-use test data using portable emission measurement devices prior to fully implementing the program.

The goal of an in-use testing program would be to ensure that emissions standards are met throughout the useful life of the engines, under conditions normally experienced in-use. We request comment on implementing an in-use testing program for marine diesel engines. In addition, we request comment on creating a similar pilot program as is anticipated for highway vehicles and nonroad land-based engines. We also request comment on any unique issues related to marine engines that may require modifications to this approach. It should be noted that such an in-use testing program would be in addition to our normal compliance and enforcement provisions.

E. Certification and Compliance

Our current marine compliance program contains provisions for engine family certification, production-line testing and in-use testing. We request comment on whether we should consider any changes or additions to our current certification and compliance programs. In addition to possible modifications to our current programs, we are asking for comment on whether an engine-diagnostic requirement would be beneficial for marine diesel engines. We currently have diagnostic programs in place for some other mobile sources. We request comment on the value of diagnostic requirements for marine diesel engines in light of our current in-use testing programs, and specifically request comment on what types of engine characteristics and components should be monitored under such a program. For example, should we consider actual onboard emissions measurement, which would require new hardware, or should we simply require that the existing sensors be utilized to better monitor for potential problems related to emission controls?

IV. Potential Environmental Impacts and Costs

A. Estimated Inventory Contribution

Locomotives and marine diesel engines contribute to the formation of ground level ozone and fine particles. Based on our current inventory analysis, we estimate that these engines contributed 12 percent and 10 percent of mobile source NO_X and diesel $PM_{2.5}$ emissions in 1996. We estimate that their contribution will increase to 27 and 45 percent of mobile source NO_X and diesel $PM_{2.5}$ emission by 2030, after phase-in of our existing locomotive and marine diesel engine emission control programs. Our current estimates for NO_X and diesel $PM_{2.5}$ inventories are set out in Tables IV.A–1 and IV.A–2. The inventory projections include the newly adopted nonroad diesel engine standards and sulfur reductions for marine and locomotive diesel fuel. Also, diesel $PM_{2.5}$ and SO_2 emissions for locomotives and marine diesel engines were adjusted downward to account for the recent fuel sulfur limits on diesel marine and locomotive fuel. While we do not provide estimates for other pollutants in this ANPRM, it should be noted that these engines also contribute to national HC, carbon monoxide, and air toxics inventories. We will estimate those inventories as part of the development of our NPRM.

Our current inventories for marine diesel engines are based on inventory work done in connection with our 1999 and 2003 marine diesel engine rules. The inventory for Category 1 marine diesel engines, which includes recreational, commercial, and auxiliary applications, is estimated using a methodology based on engine population, hours of use, average engine loads, and in-use emission factors. The inventory for Category 2 marine diesel engines is based on a combination of two approaches, one using ship registry data, engine rated power, operation, fuel consumption, and fuel specific emission factors, and the other using a cargo movement approach. Our inventory estimates assume that all these emissions occur within the U.S. airshed. Finally, the emissions for marine diesel engines less than 37 kW are estimated using the draft NONROAD2004 model.

As part of the development of our NPRM, we will be re-evaluating our marine diesel inventory with respect to Category 1 and Category 2 marine diesel engines and locomotives. We will also be investigating the localized effects of these emissions in and around ports and rail yards. We will be posting a note on our locomotive and marine Web sites that describes our plans and solicits input on several aspects of our inventory research.

TABLE IV.A–1.—ANNUAL NO_X BASELINE EMISSION LEVELS FOR MOBILE AND OTHER SOURCE CATEGORIES [a]

Category	1996			2030		
	NO_X short tons	Percent of mobile source	Percent of total	NO_X short tons	Percent of mobile source	Percent of total
Marine Diesel except C3 [b]	673,309	5.2	2.8	655,052	15.6	4.5
Locomotives	934,070	7.2	3.8	481,077	11.5	3.3
Subtotal of Affected Categories	1,607,379	12.4	6.6	1,136,128	27.1	7.8
Land-based Nonroad Diesel	1,564,904	12.1	6.4	458,649	11.0	3.2
Recreational Marine SI	33,304	0.2	0.1	67,893	1.6	0.5
Nonroad SI ≤25 hp	63,120	0.5	0.3	114,447	2.7	0.8
Nonroad SI >25 hp	273,082	2.1	1.1	43,527	1.0	0.3
Recreational SI	4,297	0.0	0.0	19,389	0.5	0.1
Commercial Marine Diesel C3	184,275	1.4	0.8	514,881	12.3	3.5
Commercial Marine Other [c]	5,979	0.0	0.0	4,020	0.1	0.0
Aircraft	165,018	1.3	0.7	258,102	6.2	1.8
Total Nonroad	3,901,357	30	16	2,617,036	62.5	18
Total Highway	9,060,923	70	37	1,566,902	37.5	11
Total Mobile Sources	12,962,279	100	53	4,183,938	100	29
Stationary Point and Area Sources [d]	11,449,752		47	10,320,361		71
Total Man-Made Sources	24,412,031			14,504,300		
Mobile Source Percent of Total		53			29	

Notes:
[a] These are 48-state inventories. They do not include Alaska and Hawaii.
[b] Marine diesel includes commercial C1, commercial C2, recreational up to 30 liters per cylinder displacement; it also includes marine diesel engines <37 kW that were included in the Tier 1 and Tier 2 standards for land-based nonroad engines.
[c] Steam and coal-powered marine vessels.
[d] Does not include the effects of the Proposed Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule). 69 FR 4566, January 30, 2004. *See http://www.epa.gov/interstateairquality/rule.html.*

TABLE IV.A–2.—ANNUAL DIESEL $PM_{2.5}$ BASELINE EMISSION LEVELS FOR MOBILE AND OTHER SOURCE CATEGORIES [a] [b]

Category	1996			2030		
	Short tons	Percent of mobile source	Percent of total	Short tons	Percent of mobile source	Percent of total
Diesel Marine [c]	18,705	4.7	4.6	17,526	27.0	25.4
Locomotives	22,266	5.6	5.5	11,599	17.9	16.8
Subtotal of Affected Categories [d]	40,971	10.3	10.1	29,125	44.9	42.2
Land-Based Nonroad Diesel	186,507	47.2	45.8	21,698	33.5	31.4
Total Nonroad Diesel	227,478	58	56	50,823	78	74
Total Highway Diesel	167,384	42	41	13,948	22	20
Total Mobile Source Diesel	394,862	100	97	64,771	100	94
Stationary Point and Area Source Diesel [e]	12,199		3	4,231		6
Total Man-Made Diesel Sources	407,061			69,002		
Mobile Source Percent of Total	[f] 97			[f] 94		

Notes:
[a] These are 48-state inventories. They do not include Alaska and Hawaii.
[b] Excludes natural and miscellaneous sources.
[c] Marine diesel includes commercial C1, commercial C2, recreational up to 30 liters per cylinder displacement; it also includes marine diesel engines <37 kW that were included in the Tier 1 and Tier 2 standards for land-based nonroad engines. It does not include commercial C3 vessels using residual fuel.
[d] When total $PM_{2.5}$ is considered, marine diesel engines and locomotives contributed 7.2% of mobile source $PM_{2.5}$ in 1996. The contribution of these sources expected to be 10.4% of mobile source $PM_{2.5}$ in 2030.
[e] This category includes point sources burning either diesel, distillate oil (diesel), or diesel/kerosene fuel.
[f] Percent.

B. Potential Costs

The emission-control technologies we are considering for marine diesel engines and locomotives are already under development or in commercial use for highway and nonroad diesel engines. To estimate the costs of this prospective emission control program, we expect to start with the cost estimates we have established in previous rulemakings for highway and nonroad diesel engines. We will modify those estimates as needed to take into account the unique aspects of locomotive and marine applications. These include different usage characteristics, engine lifetimes and rebuild schedules, and sales volumes. Additional adjustment will be made to account for the physical and operating characteristics of locomotive engines and marine diesel engines, such as size, packaging, maintenance, duty cycle, and idling patterns. We encourage commenters to review the extensive information covering all aspects of engine costs contained in the highway and nonroad diesel engine program regulatory impact analyses, and to provide comments on cost-related issues that differentiate locomotives and marine engines from highway and land-based nonroad diesel engines. In addition, we are interested in cost information associated with potential retrofitting concepts, and in information about any unique costs associated with equipment redesign for the marine market.

V. Small Business Concerns/Regulatory Flexibility

Pursuant to the Regulatory Flexibility Act (RFA, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996 5 U.S.C. 601 *et seq.*), we will perform an assessment of the impacts of the emission control program we are considering on small entities and will convene a Small Business Advocacy Review (SBAR) panel if the assessment indicates this is appropriate.

We are also planning outreach efforts independent of the SBAR panel to obtain advice and recommendations from representatives of the small entities that would likely be directly affected by a proposed rule. We anticipate beginning this outreach effort in Summer 2004. We may contact some stakeholders prior to that time to gain as much information as possible about these entities to assist us in creating useful provisions for small businesses to utilize.

We intend to offer similar regulatory flexibility provisions for small entities that were offered in previous locomotive, marine, and other nonroad rules to help decrease the burden on small entities while still meeting the environmental goals of the Agency. We also invite recommendations on additions and/or modifications of prior flexibility provisions for this rule.

The following is a list of the entities that we believe will be regulated by this rule, and their corresponding size standards, as set out by the Small Business Administration (SBA):

Category/industry	Size standards (number of employees)	NAICS [a] code
Engine manufacturers (including engine marinizers, rebuilders, and remanufacturers)	1,000	[b] 333618
Locomotive manufacturers and rebuilders	1,000	[c] 336510
Ship builders and repairers	1,000	336611
Boat builders	500	336612

[a] NAICS is the North American Industry Classification System.
[b] Diesel engine manufacturers, specifically locomotive engines, are classified in the NAICS system as "Other Equipment Manufacturing".
[c] Locomotive manufacturers and rebuilders are classified in the NAICS system as "Railroad Rolling Stock Manufacturers".

VI. Public Participation

We are committed to a full and open regulatory process with input from a wide range of interested parties and request comment on all aspects of this Advance Notice of proposal. Opportunities for input include a public comment period on this ANPRM. This section describes how you can participate in this process.

A. How Do I Submit Comments?

With today's action, we open a comment period for this advance notice. We will accept comments until by August 30, 2004. We encourage comment on all issues raised here, and on any other issues you consider relevant. The most useful comments are those supported by appropriate and detailed rationales, data, and analyses. All comments, with the exception of proprietary information, should be directed to the docket (*see* **ADDRESSES**).

If you wish to submit proprietary information for consideration, you should clearly separate such information from other comments by (1) labeling proprietary information "Confidential Business Information" and (2) sending proprietary information directly to the contact person listed (*see* **FOR FURTHER INFORMATION CONTACT**) and not to the public docket. This will help ensure that proprietary information is not inadvertently placed in the docket. If you want us to use a submission of confidential information as part of the basis for a proposal, then a nonconfidential version of the document that summarizes the key data or information should be sent to the docket. We will disclose information covered by a claim of confidentiality only to the extent allowed and in accordance with the procedures set forth in 40 CFR part 2. If you don't identify information as confidential when we receive it, we may make it available to the public without notifying you.

B. Will There Be a Public Hearing?

We will not hold a public hearing for the issues raised in this Advance Notice of proposal. However, we will hold a hearing for the issues raised in our future Notice of Proposed Rulemaking, and will provide information about that hearing when we publish the NPRM.

VII. Statutory and Executive Order Reviews

A. Administrative Designation and Regulatory Analysis (Executive Order 12866)

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is "significant" and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of this Executive Order. The Executive Order defines a "significant regulatory action" as any regulatory action that is likely to result in a rule that may:

• 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;

- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

This Advance Notice was submitted to OMB for review. Any written comments from OMB and any EPA response to OMB comments are in the public docket for this Notice.

B. Regulatory Flexibility Act

Section 605 of the Regulatory Flexibility Act (RFA), 5 U.S.C. 601 *et seq.* requires the Administrator to assess the economic impact of proposed rules on small entities. The Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, Public Law 104–121, amended the RFA to strengthen its analytical and procedural requirements and to ensure that small entities are adequately considered during rule development. The Agency accordingly requests comment on the potential impacts on a small business of the program described in this notice. These comments will help the Agency meet its obligations under SBREFA and will suggest how EPA can minimize the impacts of this rule for small companies that may be adversely affected.

Depending on the number of small entities identified prior to the proposal and the level of any contemplated regulatory action, we may convene a Small Business Advocacy Review Panel under section 609(b) of the Regulatory Flexibility Act as amended by SBREFA. The purpose of the Panel (or multiple Panels, as necessary) would be to collect the advice and recommendations of representatives of small entities that could be affected by the eventual rule. If we determine that a panel is not warranted, we would intend to work on a less formal basis with those small entities identified.

We request information on small entities potentially affected by this rulemaking. Information on company size, number of employees, annual revenues and product lines would be especially useful. Confidential business information may be submitted as described in Section VI.

C. Paperwork Reduction Act

We will prepare information collection requirements as part of our proposed rule and submit them for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*

D. Intergovernmental Relations

1. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "federal mandates" that may result in expenditures to state, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation of why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

As part of the development of our Notice of Proposed Rulemaking, we will examine the impacts of our proposal with respect to expected expenditures by state, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year.

2. 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 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "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."

As part of the development of our Notice of Proposed Rulemaking, we will examine the impacts of our proposal with respect to tribal implications.

E. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. 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. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

As part of the development of our Notice of Proposed Rulemaking, we will examine the availability and use of voluntary consensus standards.

F. Protection of Children (Executive Order 13045)

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (62 F.R. 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.

As part of the development of our Notice of Proposed Rulemaking, we will examine the impacts of our proposal with respect to whether it concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children.

G. Federalism (Executive Order 13132)

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 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."

Under Section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism 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 State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

Section 4 of the Executive Order contains additional requirements for rules that preempt State or local law, even if those rules do not have federalism implications (*i.e.*, the rules 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). Those requirements include providing all affected State and local officials notice and an opportunity for appropriate participation in the development of the regulation. If the preemption is not based on express or implied statutory authority, EPA also must consult, to the extent practicable, with appropriate State and local officials regarding the conflict between State law and Federally protected interests within the agency's area of regulatory responsibility.

As part of the development of our Notice of Proposed Rulemaking, we will examine the impacts of our proposal with respect to 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.

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.

H. Energy Effects (Executive Order 13211)

We anticipate that our proposal will not be a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. The proposed standards will have for their aim the reduction of emission from certain nonroad engines, and have no effect on fuel formulation, distribution, or use.

I. Plain Language

This document follows established EPA practices regarding the use of plain language in government writing. To read the text of the regulations, it is also important to understand the organization of the Code of Federal Regulations (CFR). The CFR uses the following organizational names and conventions.

Title 40—Protection of the Environment
Chapter I—Environmental Protection Agency
Subchapter C—Air Programs. This contains parts 50 to 99, where the Office of Air and Radiation has usually placed emission standards for motor vehicle and nonroad engines.
Subchapter U—Air Programs Supplement. This contains parts 1000 to 1299, where we intend to place regulations for air programs in future rulemakings.
Part 1045—Control of Emissions from Marine Spark-ignition Engines and Vessels.
Part 1068—General Compliance Provisions for Engine Programs. Provisions of this part apply to everyone.

Each part in the CFR has several subparts, sections, and paragraphs. The following illustration shows how these fit together.

Part 1045
Subpart A
Section 1045.1
(a)
(b)
(1)
(2)
(I)
(ii)
(A)
(B)

A cross reference to § 1045.1(b) in this illustration would refer to the parent paragraph (b) and all its subordinate paragraphs. A reference to "§ 1045.1(b) introductory text" would refer only to the single, parent paragraph (b).

List of Subjects

40 CFR Part 92

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Railroads, Reporting and recordkeeping requirements, Warranties.

40 CFR Part 94

Environmental protection, Administrative practice and procedure, Air pollution control, Confidential business information, Imports, Incorporation by reference, Labeling, Penalties, Vessels, Reporting and recordkeeping requirements, Warranties.

Dated: May 11, 2004.

Michael O. Leavitt,

Administrator.

[FR Doc. 04–11294 Filed 6–28–04; 8:45 am]

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Federal Register

Tuesday,
June 29, 2004

Part IV

Department of Transportation

Federal Aviation Administration

14 CFR Parts 121 and 135
Aircraft Assembly Placard Requirements;
Final Rule

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Parts 121 and 135

[Docket No. FAA–2004–18477]

RIN 2120–AI24

Aircraft Assembly Placard Requirements

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends the passenger information rules for scheduled air carriers. It requires a notice or placard informing passengers of the name of the country in which the aircraft was finally assembled. These changes are necessary to respond to an Act of Congress requiring the notice or placard be available to passengers no later than June 12, 2005.

DATES: This final rule is effective upon OMB approval of the information collection. When OMB approves, we will publish a document in the **Federal Register** announcing the effective date.

ADDRESSES: 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 Federal holidays.

FOR FURTHER INFORMATION CONTACT: Gary Davis, Flight Standards Service, Air Transportation Division, AFS–201A, Federal Aviation Administration, 800 Independence Avenue SW., Washington, DC 20591; telephone (202) 267–8166; facsimile (202) 267–5229, e-mail *gary.davis@faa.gov*.

SUPPLEMENTARY INFORMATION:

Availability of Final Rule

You can get an electronic copy using the Internet by:

(1) Searching the Department of Transportation's electronic Docket Management System (DMS) Web page *(http://dms.dot.gov/search);*

(2) Visiting the Office of Rulemaking's Web page at *http://www.faa.gov/avr/arm/index.cfm;* or

(3) Accessing the Government Printing Office's Web page at *http://www.gpoaccess.gov/fr/index.html*.

You can also get a copy by submitting a request to the Federal Aviation Administration, Office of Rulemaking, ARM–1, 800 Independence Avenue SW., Washington, DC 20591, or by calling (202) 267–9680. Make sure to identify the docket number, notice number, or amendment number of this rulemaking.

Small Business Regulatory Enforcement Fairness Act

The Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996 requires the FAA to comply with small entity requests for information or advice about compliance with statutes and regulations within its jurisdiction. Therefore, any small entity that has a question regarding this document may contact its local FAA official, or the person listed under **FOR FURTHER INFORMATION CONTACT.** You can find out more about SBREFA on the Internet at *http://www.faa.gov/avr/arm/sbrefa.htm*, or by e-mailing us at *9-AWA-SBREFA@faa.gov*.

Background

In Section 810 of the FAA Reauthorization Act (December 11, 2003), the Congress directed the Secretary of Transportation to require that each air carrier providing scheduled passenger air transportation display, by June 12, 2005, a notice that informs passengers of the country in which the aircraft they are aboard was finally assembled. This information is to be provided on a notice or placard available to each passenger on the aircraft.

The conference committee report accompanying the legislation interprets the statutory requirement, explaining that it calls for the information on country of final assembly to be available "on the placard in the seat back pocket" on the aircraft. Therefore, this new statement will be included on the seat-pocket cards that are already required to provide information on emergency procedures for the type and model of the aircraft.

Sections 121.571 and 135.117 require that each certificate holder provide cards that supplement the oral briefing given to passengers before takeoff. These cards contain diagrams and operating methods for emergency exit of the aircraft. This rule requires that these cards also inform each passenger of the country in which the aircraft was finally assembled. Congressional guidance made clear that this is the proper place to include the new information.

We understand that the statutorily required June 12, 2005, deadline may not provide enough time for each airline to replace every card. We will interpret our rule such that each airline can meet the new requirement by temporarily providing the requested information in the form of a sticker attached to each seat-pocket card. However, the required information must be added to the printed cards the next time the cards are printed for any reason.

This document is a final rule because there is limited time to comply with this Congressional direction, and the intent of Congress is clear. Congress has determined that providing the required information is beneficial to the public. The economic summary will provide the anticipated compliance costs.

Paperwork Reduction Act

This rule contains new information collection requirements. As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)), the FAA has submitted the information requirements associated with this final rule to the Office of Management and Budget for its review. Employees of the affected entities will likely be required to apply the required information to each seat back pocket card. Affected entities will also likely have to purchase stickers for each card. The hours worked and cost of stickers contribute to the burden. The total paperwork burden is 13,313.4 hours, costing $521,957.

International Compatibility

In keeping with U.S. obligations under the Convention on International Civil Aviation, it is FAA policy to comply with International Civil Aviation Organization (ICAO) Standards and Recommended Practices to the maximum extent practicable. The FAA has determined that there are no ICAO Standards and Recommended Practices that correspond to this regulation.

Economic Evaluation

Proposed changes to Federal regulations must undergo several economic analyses. First, Executive Order 12866 directs each Federal agency to propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs. Second, the Regulatory Flexibility Act of 1980 requires agencies to analyze the economic impact of regulatory changes on small entities. Third, the Trade Agreements Act (19 U.S.C. section 2531–2533) prohibits agencies from setting standards that create unnecessary obstacles to the foreign commerce of the United States. In developing U.S. standards, this Trade Act also requires agencies to consider international standards and, where appropriate, use them as the basis of U.S. standards. Fourth, the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in the expenditure by

State, local, or tribal governments, in the aggregate, or by the private sector, of $100 million or more annually (adjusted for inflation).

The FAA has determined this rule (1) as mandated by Congress, is deemed to be in the public interest; (2) is not a "significant regulatory action" as defined in section 3(f) of Executive Order 12866 and is not "significant" as defined in DOT's Regulatory Policies and Procedures; (3) will not have a significant impact on a substantial number of small entities; (4) will have no effect on international trade; and (5) does not impose an unfunded mandate on State, local, or tribal governments, or on the private sector.

Costs

Each of the part 121 and 135 air carriers may put a sticker on the seat-pocket card; an aircraft cleaner may do this during routine cleaning. Application of each sticker takes one minute and each sticker costs $0.50; there are a total of 750,000 passenger seats used for part 121 scheduled passenger air transportation and 3,800 seats used for part 135 scheduled passenger air transportation. A manager from each air carrier would spend 5 hours to ensure that the program is carried out successfully. The total one-time cost for part 121 air carriers is $494,100 and for part 135 air carriers is $27,800; total costs for this program sum to $522,000. All costs are one-time costs in 2004; the FAA anticipates that the information on these stickers will be incorporated directly onto the seat-pocket cards when the old cards are replaced.

Comparison of Costs and Benefits

The final rule will cost $522,000. Congress, which reflects the will of the American people, has determined that this final rule is in the best interest of the nation and therefore provides a benefit.

Regulatory Flexibility Determination

The Regulatory Flexibility Act of 1980 (RFA) establishes "as a principle of regulatory issuance that agencies shall endeavor, consistent with the objective of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the business, organizations, and governmental jurisdictions subject to regulation." To achieve that principle, the RFA requires agencies to solicit and consider flexible regulatory proposals and to explain the rationale for their actions. The RFA covers a wide-range of small entities, including small businesses, not-for-profit organizations and small governmental jurisdictions.

Agencies must perform a review to determine whether a proposed or final rule will have a significant economic impact on a substantial number of small entities. If the agency determines that it will, the agency must prepare a regulatory flexibility analysis as described in the Act.

However, if an agency determines that a proposed or final rule is not expected to have a significant economic impact on a substantial number of small entities, section 605(b) of the 1980 RFA provides that the head of the agency may so certify and a regulatory flexibility analysis is not required. The certification must include a statement providing the factual basis for this determination, and the reasoning should be clear.

For this rule, the small entity groups are considered to be part 121 and part 135 air carriers. As shown above, the cost to all part 121 air carriers is $494,100. Given 69 air carriers, the average cost per carrier is $7,160. This cost is less than 1% of the annual median revenue for an average part 121 air carrier. Not all part 121 air carriers are small businesses, but for those that are small businesses, their annual revenue far exceeds $716,100. The cost to all part 135 air carriers is $27,800. Given 81 air carriers, the average cost per carrier is $344. This cost is less than 1% of the annual median revenue for an average part 135 air carrier. Not all part 135 air carriers are small businesses, but for those that are small businesses, their annual revenue far exceeds $34,400. Thus, the FAA certifies that this action will not have a significant economic impact on a substantial number of small entities.

Trade Impact Assessment

The Trade Agreement Act of 1979 prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. The statute also requires consideration of international standards and, where appropriate, that they be the basis for U.S. standards. The FAA has assessed the potential effect of this rulemaking and has determined that it will impose the same costs on part 121 and 135 operators whether they use aircraft assembled in the United States or aircraft assembled in some other country. Therefore, it will impose no unnecessary obstacles in foreign commerce.

Unfunded Mandates Assessment

The Unfunded Mandates Reform Act of 1995 (the Act), is intended, among other things, to curb the practice of imposing unfunded Federal mandates on State, local, and tribal governments. Title II of the Act requires each Federal agency to prepare a written statement assessing the effects of any Federal mandate in a proposed or final agency rule that may result in a $100 million or more expenditure (adjusted annually for inflation) in any one year by State, local, and tribal governments, in the aggregate, or by the private sector; such a mandate is deemed to be a "significant regulatory action."

This final rule does not contain such a mandate. Therefore, the requirements of Title II of the Unfunded Mandates Reform Act of 1995 do not apply.

Executive Order 13132, Federalism

The FAA has analyzed this final rule under the principles and criteria of Executive Order 13132, Federalism. We determined that this action will not have a substantial direct effect on the States, or the relationship between the national Government and the States, or on the distribution of power and responsibilities among the various levels of government, and therefore does not have federalism implications.

Environmental Analysis

FAA Order 1050.1D defines FAA actions that may be categorically excluded from preparation of a National Environmental Policy Act (NEPA) environmental impact statement. In accordance with FAA Order 1050.1D, appendix 4, paragraph 4(j), this rulemaking action qualifies for a categorical exclusion.

Regulations that Significantly Affect Energy Supply, Distribution, or Use

The FAA has analyzed this final rule under Executive Order 13211, Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use (66 FR 28355, May 18, 2001). We have determined that it is not a "significant energy action" under the executive order because it is not a "significant regulatory action" under Executive Order 12866, and it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

List of Subjects in 14 CFR Parts 121 and 135

Air carriers, Air Taxis, Aircraft, Airmen, Aviation safety, Reporting and recordkeeping requirements, Safety, Transportation.

The Amendment

■ In consideration of the foregoing, the Federal Aviation Administration amends parts 121 and 135 of Chapter I of Title 14, Code of Federal Regulations as follows:

PART 121—OPERATING REQUIREMENTS: DOMESTIC, FLAG, AND SUPPLEMENTAL OPERATIONS

■ 1. The authority citation for part 121 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 40119, 41706, 44101, 44701–44702, 44705, 44709–44711, 44713, 44716–44717, 44722, 46105.

■ 2. Section 121.571(b) is revised to read as follows:

§ 121.571 Briefing passengers before takeoff.

* * * * *

(b) Each certificate holder must carry on each passenger-carrying airplane, in convenient locations for use of each passenger, printed cards supplementing the oral briefing. Each card must contain information pertinent only to the type and model of airplane used for that flight, including—

(1) Diagrams of, and methods of operating, the emergency exits;

(2) Other instructions necessary for use of emergency equipment; and

(3) No later than June 12, 2005, for Domestic and Flag scheduled passenger-carrying flights, the sentence, "Final assembly of this airplane was completed in [INSERT NAME OF COUNTRY]."

* * * * *

PART 135—OPERATING REQUIREMENTS: COMMUTER AND ON DEMAND OPERATIONS AND RULES GOVERNING PERSONS ON BOARD SUCH AIRCRAFT

■ 3. The authority citation for part 135 continues to read as follows:

Authority: 49 U.S.C. 106(g), 41706, 44113, 44101, 44701–44702, 44705, 44709, 44711–44713, 44715–44717, 44722.

■ 4. Section 135.117(e) is revised to read as follows:

§ 135.117 Briefing Of Passengers Before Flight

* * * * *

(e) The oral briefing required by paragraph (a) of this section must be supplemented by printed cards which must be carried in the aircraft in locations convenient for the use of each passenger. The cards must—

(1) Be appropriate for the aircraft on which they are to be used;

(2) Contain a diagram of, and method of operating, the emergency exits;

(3) Contain other instructions necessary for the use of emergency equipment on board the aircraft; and

(4) No later than June 12, 2005, for scheduled Commuter passenger-carrying flights, include the sentence, "Final assembly of this aircraft was completed in [INSERT NAME OF COUNTRY]."

* * * * *

Issued in Washington, DC, on June 21, 2004.

Marion C. Blakey,

Administrator.

[FR Doc. 04–14630 Filed 6–28–04; 8:45 am]

BILLING CODE 4910–13–P

Federal Register

Tuesday,

June 29, 2004

Part V

Department of the Treasury

31 CFR Part 50

Terrorism Risk Insurance Program; Claims Procedures; Final Rule

DEPARTMENT OF THE TREASURY

31 CFR Part 50

RIN 1505–AB07

Terrorism Risk Insurance Program; Claims Procedures

AGENCY: Departmental Offices, Treasury.

ACTION: Final rule.

SUMMARY: The Department of the Treasury (Treasury) is issuing this final rule as part of its implementation of title I of the Terrorism Risk Insurance Act of 2002 (Act). The Act established a temporary Terrorism Insurance Program (Program) under which the Federal Government will share the risk of insured loss from certified acts of terrorism with commercial property and casualty insurers until the Program ends on December 31, 2005. This rule was published in proposed form on December 1, 2003, for public comment. The final rule contains certain definitions, requirements, and procedures for insurers filing claims with Treasury for payment of the Federal share of compensation for insured losses under the Program. In particular, the final rule addresses requirements for Federal payment, initial notice of insured loss, loss certifications, the timing and process for payment, associated recordkeeping requirements, and Treasury's audit and investigation authority.

DATES: This final rule is effective July 29, 2004.

FOR FURTHER INFORMATION CONTACT: Howard Leikin, Senior Insurance Advisor, David Brummond, Legal Counsel, or C. Christopher Ledoux, Senior Attorney, Terrorism Risk Insurance Program, (202) 622–6770 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

I. Background

A. Terrorism Risk Insurance Act of 2002

On November 26, 2002, the President signed into law the Terrorism Risk Insurance Act of 2002 (Pub. L. 107–297, 116 Stat. 2322). The Act was effective immediately. The Act's purposes are to address market disruptions, ensure the continued widespread availability and affordability of commercial property and casualty insurance for terrorism risk, and to allow for a transition period for the private markets to stabilize and build capacity while preserving State insurance regulation and consumer protections.

Title I of the Act establishes a temporary Federal program of shared public and private compensation for insured commercial property and casualty losses resulting from an act of terrorism, which as defined in the Act is certified by the Secretary of the Treasury, in concurrence with the Secretary of State and the Attorney General. The Act authorizes Treasury to administer and implement the Terrorism Risk Insurance Program, including the issuance of regulations and procedures. The Program will end on December 31, 2005. Thereafter, the Act provides Treasury with certain continuing authority to take actions as necessary to ensure payment, recoupment, adjustments of compensation and reimbursement for insured losses arising out of any act of terrorism (as defined under the Act) occurring during the period between November 26, 2002, and December 31, 2005.

Each entity that meets the definition of "insurer" (well over 2000 firms) must participate in the Program. The amount of Federal payment for an insured loss resulting from an act of terrorism is to be determined based upon insurance company deductibles and excess loss sharing with the Federal Government, as specified by the Act and the implementing regulations. An insurer's deductible increases each year of the Program, thereby reducing the Federal Government's share prior to expiration of the Program. An insurer's deductible is calculated based on a percentage of the value of direct earned premiums collected over certain statutory periods. Once an insurer has met its deductible, the Federal payments cover 90 percent of insured losses above the deductible, subject to an annual industry-aggregate limit of $100 billion.

The Program provides a Federal reinsurance backstop for three years. The Act provides Treasury with authority to recoup Federal payments made under the Program through policyholder surcharges, up to a maximum annual limit. The Act also prohibits duplicate payments for insured losses that have been covered under other Federal programs.

The mandatory availability or "make available" provisions in section 103(c) of the Act require that, for Program Year 1, Program Year 2, and, if so determined by the Secretary of the Treasury, for Program Year 3, all entities that meet the definition of insurer under the Program must make available in all of their commercial property and casualty insurance policies coverage for insured losses resulting from an act of terrorism. This coverage cannot differ materially from the terms, amounts and other coverage limitations applicable to losses arising from events other than acts of terrorism. On June 18, 2004, the Secretary of the Treasury announced his decision to extend the make available requirements through Program Year 3.

As conditions for Federal payment under the Program, insurers must provide clear and conspicuous disclosure to the policyholders of the premium charged for insured losses covered by the Program and of the Federal share of compensation for insured losses under the Program. In addition, the Act requires that insurers make certain certifications to Treasury and process and submit claims for the insured loss in accordance with appropriate business practices and any reasonable procedures Treasury may prescribe.

The Act also contains specific provisions designed to manage litigation arising out of or resulting from a certified act of terrorism. Among other provisions, section 107 creates, upon certification of an act of terrorism by the Secretary, an exclusive Federal cause of action and remedy for property damage, personal injury, or death arising out of or relating to an act of terrorism; preempts certain State causes of action; provides for consolidation of all civil actions in Federal court for any claim (including any claim for loss of property, personal injury, or death) relating to or arising out of an act of terrorism; and provides that amounts awarded in actions for property damage, personal injury, or death that are attributable to punitive damages are not to be counted as "insured losses" and not paid under the Program. The Act also provides the United States with the right of subrogation with respect to any payment or claim paid by the United States under the Program.

In implementing the Program, Treasury is guided by several goals. First, Treasury strives to implement the Act in a transparent and effective manner that treats comparably those insurers required to participate in the Program and provides necessary information to policyholders in a useful and efficient manner. Second, in accord with the Act's stated purposes, Treasury seeks to rely as much as possible on the State insurance regulatory structure. In that regard, Treasury has coordinated the implementation of all aspects of the Program with the National Association of Insurance Commissioners (NAIC). Third, to the extent possible within statutory constraints, Treasury seeks to allow insurers to participate in the Program in a manner consistent with procedures used in their normal course of business. Finally, given the temporary and transitional nature of the Program, Treasury is guided by the Act's goal that insurers develop their own capacity, resources, and mechanisms for terrorism insurance coverage when the Program expires.

B. Previously Issued Interim Guidance and Regulations

To assist insurers, policyholders, and other interested parties in complying with immediately applicable requirements of the Act prior to the issuance of regulations, Treasury promptly issued interim guidance. The interim guidance addressed certain immediately applicable provisions that required clarification and was to be relied upon by insurers until superseded by regulations or a subsequent notice.

Treasury's first notice of Interim Guidance was published in the **Federal Register** at 67 FR 76206 on December 11, 2002, and addressed, among other matters, statutory disclosure obligations of insurers as conditions for Federal payment under the Program; the requirement that an insurer "make available" terrorism insurance; and how insurers were to calculate the "direct earned premium" received from commercial lines of property and casualty insurance as well as their "insurer deductibles" for purposes of the Program. The second notice of interim guidance was published at 67 FR 78864 on December 26, 2002, and provided guidance concerning which insurance companies were "insurers" for purposes of the Program, including their "affiliates." It also addressed the scope of insured losses covered by the Program and calculation of insurer deductibles. Treasury's third notice of interim guidance was published at 68 FR 4544 on January 29, 2003. It clarified certain disclosure and certification requirements, and addressed issues concerning non-U.S. insurers, and the scope of the term "insured loss" under the Act.[1] These interim guidance notices have now been superceded by a series of interim final and final regulations issued by Treasury.

On February 28, 2003 (68 FR 9804) Treasury published an interim final rule that laid the groundwork for Program implementation, including the scope of the Program and key definitions. This interim final rule was finalized and published in the **Federal Register** at 68 FR 41250 (July 11, 2003) (as amended at 68 FR 48280 (Aug. 13, 2003)) and created subpart A of part 50 in title 31 of the Code of Federal Regulations. Treasury's second interim final regulation created subparts B and C of part 50 and addressed disclosures that insurers must make to policyholders as a condition for Federal payment under the Act, and requirements that insurers make available, in their commercial property and casualty insurance policies, terrorism risk coverage for insured losses under the Program. It was published in the **Federal Register** at 68 FR 19301 (Apr. 18, 2003). After review of comments, this interim final rule was finalized and published at 68 FR 59720 (Oct. 17, 2003).

Treasury has also issued a regulation applying the Act to State residual market insurance entities and State workers' compensation funds. In this regard, Treasury created a subpart D to part 50 of title 31, which was first proposed and published in the **Federal Register** at 68 FR 19309 (Apr. 18, 2003). After review of comments Treasury finalized and published this rule at 68 FR 59715 (Oct. 17, 2003).

C. The Proposed Rule (Claims Procedures)

The proposed rule on which this final rule is based was published in the **Federal Register** at 68 FR 67100 on December 1, 2003. In subpart F to part 50 of title 31, Treasury's proposed rule contained requirements and procedures for insurers that file claims for payment of the Federal share of compensation for insured losses resulting from a certified act of terrorism under the Act. In particular, the proposed rule revised the regulatory definition of "insured loss," provided for an initial notice of insured loss and loss certifications, set forth general requirements for Federal payment under the Program and addressed the timing and process of such payment. Subpart G addressed information to be retained related to the handling and settlement of claims to enable Treasury to perform financial and claim audits.

II. Summary of Comments and Final Rule

In the event that it had been necessary to activate the Program's claims procedures prior to the issuance of this final rule, Treasury was prepared to do so on an expedited basis. Such action, however, was not necessary and Treasury is now issuing this final rule after careful consideration of all comments received on the proposed rule and after consultation with the NAIC. While this final rule largely reflects the proposed rule, Treasury has made several revisions and a number of clarifications based on the comments received.

Treasury received comments on the proposed rule from four national insurance industry trade associations, collectively, as well as individually, a national risk retention trade association, a national lender trade association, a national surety trade association, a national agent and broker association, a captive insurers association, three insurance companies, a group of London-based insurers, a consulting actuarial firm, a vendor of insurance services, and a legal firm representing captive insurers. As described in detail below, commenters generally agreed with the proposed rule. However, Treasury received many requests to add a process for advance payments and for clarification of specific payment requirements and processes. In response, Treasury has revised the proposed rule to allow advance payments under certain conditions. In addition, Treasury has clarified provisions in the proposed rule that pertain to loss certifications requirements, payments to affiliated groups, prohibitions on duplicative compensation from other Federal programs, and the adjustment and suspension or denial of payments. Several commenters also requested that Treasury add specific references in the claims rule for State residual market insurance entities and Treasury has done so in the final rule. The comments received and Treasury's revisions to the proposed rule are summarized below.

A. Definition of Insured Loss (Section 50.5)

The final rule amends the previously issued definition of "insured loss" at § 50.5(e) to clarify that certain loss adjustment expenses allocable to a specific underlying loss are part of an insurer's insured losses and will be included in the Federal share of compensation under the Program. This clarification follows customary practices of the insurance industry with regard to reinsured losses. The definition has also been amended by the final rule to clarify that an insurer's payments in excess of policy limits or payments due to an insurer's extra-contractual obligations will not be considered as an insurer's insured loss. In addition, because section 107(a)(5) of the Act explicitly states that punitive damages are not to be considered as insured losses, the definition has been further amended to exclude compensation to an insurer for any payments attributable to punitive damages.

[1] Treasury's fourth interim guidance, published at 68 FR 15039 on March 27, 2003, provided insurers a procedure by which they could seek to rebut a presumption of control established in Treasury's interim final regulations. The Interim Guidance has subsequently been superseded by a provision in the final rule for subpart A of part 50, title 31 published at 68 FR 41250 (July 11, 2003).

1. Allocated Loss Adjustment Expense

In § 50.5(e)(3) of the proposed rule, Treasury proposed to revise the definition of the term "insured loss" to include certain loss adjustment expenses incurred by an insurer in connection with insured losses, specifically those expenses "that are allocated and identified by claim file in insurer records, including expenses incurred in the investigation, adjustment and defense of claims, but excluding staff adjuster salaries and any allocations of other internal insurer expenses." In the preamble to the proposed rule, Treasury noted that this was consistent with customary insurance industry business practices.

Three comments addressed the proposed rule's treatment of these allocated loss adjustment expenses (commonly known in the insurance industry as ALAE) within the definition of insured loss. An insurance industry trade association commended Treasury noting that, "this is consistent with industry practices and certainly appropriate." However, an individual insurance company commented that this description of ALAE would not provide equal indemnification to insurers employing staff adjusters versus those using outside, or independent, adjustors. Another insurer expressed concern that certain expenses would be excluded under § 50.5(e)(3) of the proposed rule. Expenses cited were, "traveling to investigate the site of a loss, attend an examination, or perform some other function related to a specific claim" if incurred by insurer staff adjusters.

Treasury has considered the comments presented and believes that the proposed rule generally reflected its intention to follow the Act's objectives of a system of shared public and private compensation for insured losses, including the unpredictable adjustment expenses directly associated with such losses. In particular, Treasury believes that the treatment of staff salaries in the proposed rule remains consistent with the Congressional findings and purposes of the Act and treats insurers participating in the Program comparably. Expenses such as staff salaries and other internal insurer expenses that are known and incurred regardless of the occurrence of any certified act of terrorism are not suitable to be shared with the general taxpayers and thus are not included in the definition of insured loss.

The specific approach taken toward staff adjuster and other expenses in § 50.5(e)(3) of the proposed rule is consistent with accepted practices in the reinsurance industry and with the broader objectives for the Act. However, for added clarity, Treasury has modified § 50.5(e)(3) in the final rule to specifically exclude "staff salaries, overhead, and other insurer expenses that would have been incurred notwithstanding the insured loss" from the definition of insured loss. Consistent with this approach, reasonable, allocated expenses for travel to investigate the site of a loss, attend an examination, or perform some other function related to the investigation, adjustment and defense of a specific claim, even if incurred by insurer staff adjusters, are included in the definition of insured loss.

2. Extra-Contractual Obligations

The proposed rule also revised the definition of "insured loss" to clarify that the Federal Government would not share in an insurer's payment of extra-contractual damages. Extra-contractual obligations describe an insurer's liability to pay damages to its insured or a third party due to the insurer's breach of the insurance policy and/or negligent or bad-faith claims-handling conduct, including liability for punitive, exemplary, or special damages awarded or paid as a result of such conduct.

Several insurance industry trade groups commented that Treasury's proposed rule should be revised to allow for the federal payment of extra-contractual obligations paid by an insurer. Extra-contractual obligations paid by an insurer are the result of an insurer's conduct and are not part of "insured loss" or directly associated with adjusting the loss as is the case with ALAE. Accordingly, such losses are not to be paid under the Program. The final rule adopts § 50.5(4) of the rule as proposed, with some minor modifications to the language.

In commenting on extra-contractual obligations, one trade group stated that in the light of unique situations following an act of terrorism, insurers "may go beyond the contract language to indemnify an insured." Such payments by an insurer would not be an "insured loss" because the paid loss is not covered by the terms and conditions of the insurance policy. Treasury considered the comment and has determined to adopt § 50.50(a)(6) of the proposed rule without change in the final rule.

3. Excess Policy Limits Payments

The definition of "insured loss" in the proposed rule did not include losses in excess of policy limits (known commonly in the insurance industry as XPL). XPL losses occur when the liability of the insured to a third party is in excess of that policy limit but otherwise within the scope of the insurance coverage. Under certain circumstances, an insurer will pay XPL losses to or on behalf of its insured (*e.g.*, when an insurer fails to accept a settlement offer within policy limits and a jury later finds the policyholder liable in an amount in excess of policy limits). In the preamble to the proposed rule, Treasury specifically invited comments on whether Treasury should include XPL losses within the definition of "insured loss."

One commenter who addressed the issue of XPL losses pointed out that excess of loss reinsurance treaties usually include clauses providing reinsurance coverage for XPL claims. Treasury recognizes that such clauses are sometimes negotiated into reinsurance treaties. However, Treasury had determined not to include such losses in the definition of "insured loss" because such excess losses are not part of "insured loss" or directly associated with adjusting the loss. Given the lack of additional reasons to include XPL, the final rule adopts Treasury's proposed language, with a technical correction at § 50.5(e)(4)(iii).

4. Losses by State Residual Market Mechanisms

Three comments were received from insurance trade associations, submitted individually and collectively, concerning the proposed rule not specifically addressing losses by State residual market insurance entities and State workers' compensation funds (hereafter referenced as State residual market mechanisms). The commenters offered language to explicitly include, in the definition of insured losses, those losses allocated on a proportionate share basis from a State residual market mechanism to a participating insurer. Treasury has determined that it is not necessary to amend the definition of insured loss for this purpose, but has addressed this issue through clarifications to §§ 50.50 and 50.53 regarding the treatment of residual market losses. These changes are discussed below.

B. Federal Share of Compensation (Section 50.50)

The final rule provides that the Federal share of compensation under the Program is 90 percent of that portion of the insurer's insured losses that exceed its insurer deductible during a Program Year, subject to specified adjustments and the annual industry aggregate limit of $100 billion as provided in the Act. This section also addresses requirements for federal payment and situations under which Treasury may deny or suspend payment.

1. General Clarifications

In § 50.50(a), Treasury has revised the proposed rule to clarify that the Federal share of compensation will be paid once a Certification of Loss required by § 50.53 of the final rule is deemed sufficient. Section 50.50(a)(1) was changed slightly to make clear that the insurer, including all affiliates of the insurer, must meet the requirements of § 50.5(f). Also, § 50.50(a)(4) has been revised to clarify that Treasury will pay so long as the underlying insured loss—as well as the insurer's claim for Federal payment—is not fraudulent, collusive, made in bad faith, or dishonest. In addition, under § 50.50(4) of the final rule, neither the underlying claim for insured loss nor the insurer's claim will be paid if Treasury determines that the claim is designed to circumvent the purposes of the Act and regulations. This is intended to discourage those who may attempt to "game" the Program.

Section 50.50(a) of the proposed rule provided that payment of the Federal share of compensation would occur upon Treasury making a determination as to the factors listed therein. This section of the proposed rule provided that Treasury may make a payment without this determination, subject to a "reservation of rights." As that term is commonly understood in the insurance industry, payment subject to a "reservation of rights" facilitates prompt payment because the payment is not construed as a waiver by the payee of any preconditions to payment. Although Treasury has eliminated the "reservation of rights" language in the final rule, Federal payment is still subject to Treasury's statutory authority as administrator of the Program to examine, or re-examine the factors listed in § 50.50(a) as part of a claims review or audit. This is now reflected in § 50.50(b) of the final rule. Treasury has statutory authority to subsequently adjust, or require repayment of any federal payment under the Act.

2. State Residual Market Mechanisms

As previously noted in the discussion of § 50.5, Treasury received comments with regard to the distribution of losses to participating insurers from State residual market mechanisms described in section 103(d)(2)(B) of the Act. A comment jointly provided by four insurance industry trade associations suggested that the proposed rule be revised to recognize losses paid by participating insurers as their share of residual market losses. Treasury concurs with the need to clarify the treatment of losses paid as a share of residual market losses. Section 50.50(a)(2) has been revised to make clear that the insurer's insured losses include "the allocated dollar value of the insurer's proportionate share of losses from a State residual market entity or State workers' compensation fund."

3. Advance Payments

Section 50.50(a) of the proposed rule provided that the amount of payment of the Federal share of compensation would be based, in part, upon a Treasury determination that, the "insurer has made payment of an underlying insured loss to a person who had suffered the insured loss, or to a person acting on behalf of such person * * *." This proposed an approach whereby Treasury would pay the Federal share of compensation strictly as a reimbursement for amounts actually paid by insurers for underlying insured losses, whether fully or partially settled. This approach was also followed in § 50.53 of the proposed rule (Loss Certifications), which required, in part, a certification that the insurer had paid all underlying claims comprising the insured losses submitted for payment, as listed in the bordereau provided pursuant to § 50.53(b)(1).

Treasury received six comments on the timing of Federal payments. With some variation, the common theme was the issue of whether an insurer would receive the Federal share of compensation before or after the insurer's payment of underlying insured losses. The commenters, one insurer, three trade associations and one law firm on behalf of a trade association, contended that adherence to the pure reimbursement approach is not required by the Act. It was asserted that insurers may need to receive the Federal share of compensation for an insured loss in advance of their actual payment because of liquidity problems, particularly in the financial environment following a certified act of terrorism. The commenters explained that reinsurance industry practice permits advance or simultaneous payments subject to certain controls.

Treasury carefully considered these comments and determined that there may be some circumstances in which it would be appropriate for Treasury to advance payment for the Federal share of compensation for insured losses. Section 104(b)(2) of the Act authorizes the issuance of rules or procedures specifying the manner in which payments of the Federal share of compensation may be made based on estimates of insured losses. In the final rule, Treasury has revised § 50.50 of the proposed rule to permit insurers to include on their bordereau requests for payment of the Federal share of compensation for both (1) claim payments already made, and (2) claim payments about to be made. This applies to partial as well as final settlements of underlying claims that comprise an insurer's insured losses.

Under the final rule, insurers are required to certify that any advances for underlying insured losses that have been requested will be paid within five business days of receipt of funds from Treasury. In addition, any interest earned on such funds will be remitted to the Treasury. Treasury believes that this provides an appropriate balance between meeting the cash flow needs of participating insurers and the proper stewardship over public funds.

To permit advanced payments, § 50.50(a)(3) of the proposed rule has been revised in the final rule to recognize that an insurer "has paid or is prepared to pay an underlying insured loss." Section 50.53(b)(2)(i) also has been revised to provide that underlying losses on the insurer's bordereau "either: Have been paid by the insurer; or will be paid by the insurer upon receipt of an advance payment of the Federal share of compensation as soon as possible, consistent with the insurer's normal business practices, but not longer than five business days after receipt of the Federal share of compensation." Also, a new subsection (d) has been added to § 50.54 Payment of the Federal Share of Compensation, that requires insurers seeking advanced payments to establish segregated interest-bearing accounts for the receipt of such payments and for the disbursement of those payments to insureds and claimants.

4. Full Payment for All Insured Losses

One comment was received from a trade association that understood the proposed rule as requiring insurers to make payment in full of all insured losses before becoming eligible for the Federal share of compensation. This is a misreading of the proposed rule and no change to the rule is required.

5. Denial or Suspension of Payment

Section 50.62 of the proposed rule provided generally that an insurer may be ineligible to receive payment of the Federal share of compensation for insured losses upon a determination by Treasury that the insurer intentionally concealed or misrepresented any material fact or circumstance, engaged in fraudulent conduct, or made false statements relating to participation under the Act.

A national insurance trade association commented on § 50.62. This commenter noted that section 103(b) of the Act sets forth the grounds under which an insurer may be ineligible to receive Federal payments and that section 104(e) of the Act provides Treasury with civil money penalty authority. If any of the conditions for payment of the Federal share in section 103(b) have not been met with respect to a particular insured loss, the commenter suggested that the appropriate response of Treasury would be to deny payment for that insured loss. Similarly, the commenter suggested that if there is wrongdoing, such as fraud or misrepresentation, Treasury could assess civil money penalties under section 104(e) of the Act. The commenter concluded that these provisions "cover the landscape of potential offenses" and thus viewed the provisions of § 50.62 to be overbroad. The commenter recommended that § 50.62 be deleted or revised.

Treasury concurs that sections 103(b) and 104(e) provide Treasury with broad authority to deny or suspend payment and/or to assess civil money penalties in connection with insurer requests for payment of the Federal share of compensation under the Act. Treasury has determined to delete § 50.62 as the commenter requested and to address certain issues through revisions to § 50.50.

Treasury believes there may be circumstances where failure to meet one of the requirements for payment of the Federal share of compensation with respect to one insured loss may be an indication of a broader pattern or practice of malfeasance or wrongdoing on the part of the insurer with regard to its other claims for insured losses. To address this, Treasury has added a new subsection (c) to § 50.50 that provides, in Treasury's discretion, for suspension of payment for other insured losses of an insurer if the insurer fails to meet one of the requirements in § 50.50(a). In such cases, Treasury may decide to conduct additional review and investigation of the insurer's Loss Certification submissions before paying the Federal share of compensation.

C. Adjustments to the Federal Share of Compensation (Section 50.51)

The final rule specifies several adjustments in calculating the Federal share of compensation. First, the rule reduces aggregate insured losses by amounts recovered by insurers for salvage and subrogation. Second, the rule provides that, should the amount of an insurer's Federal share of compensation from the Program and the amount of recoveries from other sources exceed the aggregate amount of its insured losses in a Program Year, then any excess recovery must be returned to Treasury. Excluded from this requirement are recoveries from a reinsurer pursuant to an agreement whereby an insurer's obligation to repay its reinsurer takes priority over its obligation to repay Treasury. Third, the rule in § 50.51 follows the Act's requirement that the Federal share of compensation for insured losses be reduced by any duplicate amount of compensation otherwise provided by the Federal government for those insured losses.

1. Salvage and Subrogation

Treasury received three comments on the salvage and subrogation provisions of 50.51(a). One commenter, an insurer, noted that the preamble to the proposed rule expressed Treasury's expectation that, "as normal good business practice, insurers will pursue salvage and subrogation." The commenter was concerned that this language and the proposed rule did not explicitly address the flexibility of the insurer to use its own business discretion to pursue, abandon or forego salvage and/or subrogation efforts. Treasury believes that normal business practice requires the use of discretion in determining salvage and/or subrogation efforts. Treasury does not believe a change to the proposed rule is required and expects insurers to use the appropriate discretion in pursuing salvage and/or subrogation opportunities.

This same commenter requested clarification regarding the cost of pursuing salvage and/or subrogation. The rule states that the insurer's aggregate insured losses used to calculate the Federal share of compensation shall be reduced by any salvage or subrogation recoveries. Treasury agrees that insurers should be able to recover the costs of pursuing salvage and subrogation actions. It is expected that these expenses will be included by insurers in Allocated Loss Adjustment Expenses. Because such reasonable expenses are included in the definition of insured loss, Treasury sees no need to further change the rule to resolve this issue. Additional guidance on the treatment and netting of expenses will be included in the definitions for the fields reported on the bordereau form submitted with the Certifications of Loss.

A trade association commented that some insurers do not currently capture salvage and subrogation recoveries independent of one another and sought relaxed reporting requirements. Treasury prefers to receive this information separately, but in the interest of minimizing changes to insurers' existing processes Treasury will accept reports with salvage and subrogation recoveries combined or separate. This accommodation will be accomplished in the bordereau format and instructions which are soon to be published (along with other forms) for public comment.

2. No Excess Recoveries

Section 50.51(b)(1) of the proposed rule provided that in any Program Year the sum of the Federal share of compensation paid to an insurer and the insurer's recoveries for insured losses from other sources shall not be greater than the insurer's aggregate losses for acts of terrorism in that Program Year. This is consistent with section 103(g)(2) of the Act.

One commenter suggested that ceding commissions received by an insurer in reinsuring its deductible and retentions under the Act could be considered part of an insurer's recovery. Ceding commissions are compensation from a reinsurer to a ceding insurer for the costs of writing underlying policies and are paid regardless of whether claims are ever submitted. It is Treasury's view that ceding commissions are not recoveries from other sources for insured losses and, therefore, the Federal share of compensation shall not be reduced by such commissions. No change has been made to the proposed rule in this regard.

Section 50.51(b)(1) of the proposed rule also provided that amounts recovered for insured losses in excess of an insurer's aggregate amount of insured losses in a Program Year be repaid to Treasury within 45 days after the end of the month when such amounts are received by the insurer. A trade association commented that it may take a long time after actual receipt of recoveries before an insurer is able to determine whether a recovery is excess. The commenter suggested that repayment be required 45 days after the insurer becomes aware that the recovery is excess.

Treasury recognizes that the determination of a recovery being excess may occur some time after the actual receipt of that recovery. However, Treasury believes that the commenter's alternative, based on when the insurer becomes "aware" of any excess recovery, is too vague to establish a definitive schedule for the repayment of funds. The final rule has been clarified in § 50.51(b)(1) so that amounts recovered for insured losses in excess of an insurer's aggregate amount of insured losses in a Program Year are to be repaid to Treasury based on when total recoveries of the insurer, from all sources, become excess.

3. Compensation From Other Federal Programs

Section 103(e)(1)(B) of the Act states, "The Federal share of compensation for insured losses under the Program shall be reduced by the amount of compensation provided by the Federal Government to any person under any other Federal program for those insured losses." To implement this statutory provision, § 50.51(b)(2) of the proposed rule stated, "The Federal share of compensation due an insurer for insured losses shall be reduced by any amounts received by the insurer or an insured or a third party suffering the underlying loss from any other Federal programs as compensation for those insured losses, including, but not limited to, insurance, assistance, grants or disaster relief from the Federal Government." Nine comments addressed § 50.51(b)(2). After consideration of the comments and upon further analysis, Treasury has made several revisions in the final rule and is providing additional explanation in this preamble for greater guidance.

As a preliminary matter, Treasury has made a few technical corrections to the final rule. The proposed rule explained that any reduction would be based on the amount of compensation received by the insurer or an insured or a third party suffering the underlying loss. This provision in the final rule no longer makes reference to amounts received or compensation provided to insurers. This is because amounts received by insurers are covered in § 50.51(b)(1), which addresses recoveries by insurers from all other sources, including compensation received by the Federal Government. Second, the language of 50.51(b) is being revised from "any amounts received by" to "compensation provided by other Federal programs to" an insured or a third party to parallel the statutory language found in section 103(e)(1)(B) of the Act.

a. *Types of Compensation Used To Reduce the Federal Share.* In its proposed rule, Treasury described the type of compensation provided by other Federal programs in reducing the Federal share of compensation to insurers as "insurance, assistance, grants, or disaster relief." In its final rule, Treasury is providing clearer guidance on what constitutes compensation provided by other Federal programs for insured losses. Section 50.51(b)(2)(i) of the Final Rule provides that compensation provided by other Federal programs for insured losses means compensation that is provided by Federal programs established for the purpose of compensating persons for losses in the event of emergencies, disasters, acts of terrorism, or similar events. Compensation provided by other Federal programs that could be considered duplicate compensation include, but are not limited to, compensation provided under Federal programs such as:

- Federal Emergency Management Agency (FEMA) disaster relief and emergency assistance;
- Department of Housing and Urban Development block grant assistance; and
- Federal programs specially established to compensate victims for losses resulting from the certified act of terrorism (similar to the September 11th Victim Compensation Fund of 2001 (Pub. L. 107–42, 115 Stat. 237, § 401 *et seq.*)).

However, it is Treasury's view that Congress did not intend to reduce the Federal share of compensation due to receipt of Social Security disability payments and other similar benefits. Accordingly, § 50.51(b)(2)(i) of the final rule provides that compensation provided by Federal programs for insured losses excludes benefit or entitlement payments such as those made under the Social Security Act, those made under laws administered by the Secretary of Veteran Affairs, railroad retirement benefit payments, and other types of similar benefit payments. These types of Federal entitlement or benefit payments to individuals are the result of services performed and are paid irrespective of whether the loss occurs as a result of an act of terrorism. Under the final rule they are not treated as duplicate compensation for insured losses arising from an act of terrorism and shall not be used by Treasury to reduce the Federal share of compensation due an insurer.

b. *Statutory Requirement That the Federal Share Be Reduced.* Several commenters criticized the Act's requirement that the Federal share of compensation be reduced by compensation provided by the Federal Government under other Federal programs for insured losses. Several commenters acknowledged that it is a legitimate goal that no one should receive a double recovery for a loss. In developing this rule, Treasury understands that its reduction of the Federal share of compensation does not, in turn, reduce the amount insurers are obligated to pay under the terms and conditions of their insurance policies. This was pointed out by several commenters. Nevertheless, Treasury must follow the Act.

Based upon a review of how several other Federal programs would likely treat proceeds from "property and casualty insurance," under the Act or otherwise, Treasury expects that duplicative compensation situations will be rare. This is because the most likely Federal programs identified by Treasury as potential sources of duplicate payments already guard against duplicate compensation.

For example, HUD and FEMA programs offset their payments by insurance proceeds received or expected to be received by their applicants. These programs also have procedures to recoup their payments from recipients of assistance to the extent those recipients later receive insurance proceeds. Further, it is expected that Congress will include mechanisms to prevent double Federal recovery in programs designed to help victims of future acts of terrorism, much in the same way the September 11th Compensation Fund of 2001 treats collateral source payments. Moreover, any payments from other Federal insurance programs should be offset by operation of the "other insurance" clauses in insurers' standard policy forms for commercial property and casualty insurance. Finally, insurers themselves can discount settlement offers to reflect payments received from other Federal programs and in that way avoid the problem of compensation being duplicative. For claims that do not settle and proceed to award, some states allow or require reductions based on collateral source payments.

One commenter acknowledged that the proposed rule generally follows section 103 of the Act, but nevertheless concluded that section presents a "serious contractual problem" for insurers because insurance contracts do not allow for any reduction of amounts paid to insureds, other than for payments made under other insurance policies. Also, the commenter explained that because insurers' cannot forecast the amount by which their payment will be reduced, insurers cannot factor the reduction into the price of their premiums. The commenter suggested that § 50.53(b)(1) of the proposed rule be revised by deleting the words "or insured or third party suffering the underlying loss" or if that is not possible, that the Federal Government require that the insured reduce the amount of its claim presented to the insurer.

Treasury has considered the comment but has determined not to accept either suggestion. The language in section 103 requires that Treasury reduce its payment to insurers by the amount of compensation provided "to any person" for those insured losses. Insureds or third party claimants who suffer the underlying insured loss are included in the definition of "person[s]," in section 102 of the Act. However, nothing in the Act or Treasury's regulations would prevent an insurer from pursuing changes to its policies (including obtaining any necessary State regulatory approval) in order to address this reduction and allow for possible offset.

Another commenter asserted that the proposed rule "is neither logical nor equitable, and does not serve the underlying purpose of 103(e)(1)(B)." According to the commenter, it was not the intent of Congress to transfer the risk of double recovery to insurers. The commenter does not believe there should be any reduction of the insurer's Federal payment but that insurers are willing to assist Treasury in identifying those persons that have received double Federal recovery for insured losses. Treasury does not share the commenter's view. The statutory language requires Treasury to reduce the Federal share of compensation by the amount of compensation provided by the Federal Government to any person under any other Federal program for insured losses.

This same commenter also suggested that the subrogation provisions of the Act are available to prevent double recoveries. Section 107(c) of the Act provides that the United States shall have the right of subrogation with respect to any payment or claims paid by the United States under title I of the Act. Upon payment to an insurer, the United States becomes subrogated to the rights of the insurer (to the extent of the payment). Yet, as many of the commenters pointed out, the terms and conditions of standard commercial property and casualty policies do not provide the insurer with any right of offset or recoupment of amounts paid by other Federal programs. Therefore, section 107(c) may not be effective in guarding against double Federal payment. Furthermore, even if the exercise of the United States' subrogation rights could avoid the Federal Government paying twice for the same loss, the commenter's approach shifts the responsibility to pursue subrogation to the United States. Under § 50.50(a)(6), insurers are to process claims in a manner consistent with appropriate business practices, which include pursuing subrogation recoveries when appropriate. The responsibility to pursue recoveries though subrogation lies with the insurer in the first instance. The United States retains the ability to pursue such recoveries in the event the insurer does not.

c. *Other Federal Compensation Already Offset in the Underlying Claim for Insured Loss.* A trade association commented that the Federal share of compensation should not be reduced if in fact the payments by the other Federal program are already offset in the insurance claim to the insurer. If the insurance claim is already reduced, there is no duplicate compensation. The commenter is concerned that the proposed rule could be read to require the reduction of the payment to the insurer even though the insured or third party did not claim, and the insurer did not pay, for that part of the insured loss. To address this, the association recommended that Treasury clarify the proposed rule to make clear that there will be no reduction in Federal payments if the losses compensated for by the other Federal program are not also paid by the insurer. Based on the commenter's suggestion, language has been added to the final rule that clarifies the Federal share of compensation shall be reduced only "to the extent such other compensation duplicates the insurance indemnification for those insured losses." When the insurer's payment has not been offset, the Federal share shall only be reduced by the amount, if any, that the aggregate of the insurer's payment and the compensation from the other Federal program exceed the total loss. This is because the other compensation is not duplicating the payment for insured losses until there is an excess recovery.

The commenter also questioned what would happen in the situation where other Federal programs require their claimants to pursue other recoveries (such as insurance proceeds) and then to repay the other program. Would the insurer be credited for any repayment to the other Federal program? In such a situation, the Federal share of compensation would be reduced pending the claimant's repayment to the other Federal program. Once the claimant repays the other Federal program, presumably out of the insurance proceeds, the Program will pay the insurer the amount of the reduction. This will occur after the other Federal program notifies Treasury that the recipient of the insurance proceeds has repaid the other Federal program.

d. *Insurer Due Diligence.* Section 50.51(b)(2) of the proposed rule stated, "Each insurer shall inquire of each of its claimants whether or not duplicate payments for insured losses have been paid from other Federal sources. Such amounts shall be reported with each underlying claim on the bordereau specified in § 50.53(b)(1) and the total amount subtracted from the aggregate amount claimed as the Federal share of compensation for insured losses." Generally, all of the commenters viewed this information collection requirement as reasonable. Three commenters addressed the information insurers would need to obtain from claimants and suggested various approaches and forms to be used by insurers to collect information about duplicate compensation from other Federal sources. Treasury will be issuing a notice and publishing forms for public comment at a later date.

Another commenter pointed out that the proposed rule did not address the situation where an insurer pays a claim before the person receives compensation from another Federal program. This may occur when the person has not yet applied for such compensation from the other program despite being eligible or the person later becomes entitled to compensation (*e.g.*, a program set up at a later date). Having considered this comment, Treasury has modified the rule to require insurers to inquire of their policyholders, insureds, and claimants not only whether the person receiving the insurance proceeds has received compensation from another Federal program but also whether it expects to receive, or is entitled to receive compensation from another Federal program for the insured loss, and if so, the source and amount of the compensation received or expected. An insurer will be expected to collect this information at the time of claims settlement. Consistent with the insurance industry's business practice, Treasury will not require the insurer to re-open its closed claim file simply to collect this information, which can be obtained from the other Federal programs.

Although § 50.51(b)(2)(ii) of the final rule requires insurers to inquire about duplicate compensation—expected, as well as received—the Federal share of compensation will be reduced only by those amounts actually provided by the other Federal program. If a person informs an insurer that it has not yet received but expects to, or is entitled to receive compensation for another Federal program for the insured losses, Treasury will notify the other Program.

Another commenter, a "federally approved" insurer, commented that it would not have to inquire about duplicate Federal compensation because awards under the Longshore and Harbor Workers' Compensation Act ("LHWCA") (33 U.S.C. 901, *et seq.*) already take such payments into account. In such a situation, however, the final rule will still require the insurer to inquire about possible duplicate compensation since there may be sources of Federal payments for LHWCA claimants that are not taken into account under that Act.

e. *False Information Submitted to the Insurer.* Another commenter asserted that insurers have no way of ensuring that its policyholders, insureds, or claimants will reveal information concerning duplicative payments. The comment suggested that Treasury add penalties or warn persons attempting to collect twice. The final rule only requires that insurers inquire concerning duplicate compensation and report the response received. If Treasury learns that a person who has received an insurance payment shared by the Program has also received compensation for those insured losses from another Federal program, the insurer's Federal share of compensation shall be reduced.

4. Claims Handling

A commenter referenced § 50.51(b)(2) as well as § 50.51(a) and asserted that the regulations should "make it clear that the Treasury does not wish to exercise any authority over claims handling." The commenter's observation is incorrect. Treasury is responsible for the financial integrity of the Program. Section 50.50, which provides the basis for Treasury to determine the amount of the Federal share of compensation to insurers, is designed to allow Treasury to review the insurer's handling of underlying claims for insured losses. For example, § 50.50(a)(6) provides that Treasury will examine whether the insurer took all steps reasonably necessary to properly and carefully investigate the underlying insured loss and otherwise processed the underlying loss using appropriate insurance business practices. Section 50.50(a)(7) indicates that Treasury will review whether the insured losses submitted for payment are within the scope of coverage issued by the insurer. In order for it to properly carry out its financial responsibilities, Treasury will, as needed, audit insurer requests for compensation, including the handling of underlying claims, as provided in subpart G of the rule.

D. Initial Notice of Insured Loss (Section 50.52)

The final rule includes an early notification requirement when an insurer obtains information indicating its insured losses will exceed 50 percent of its insurer deductible as defined by the Act. At that time, the insurer is required to submit, on a form prescribed by Treasury, estimates of aggregate losses for the Program Year, its insurer deductible and the Federal share of aggregate losses, as well as the name of the person designated to make required certifications and receive Federal payments. Such information will assist in estimating funding levels for certified acts of terrorism and otherwise facilitate operations of the Program. Because the insurer deductible applies collectively to all insurers in an affiliated group, the notice must include the designation of a single insurance entity to coordinate the submission of required reports and documentation (including the Initial Notice of Insured Loss), make required certifications and receive Federal payments on behalf of the affiliated group.

No comments were received specific to this section of the proposed regulation. However, as a result of changes made to § 50.54 in response to comments regarding the designated single payee in an affiliated group, this section has also been revised. The Initial Notice of Insured Loss is to include a "designated insurer" as a single point of contact in an affiliated group for "receiving, disbursing, and distributing" payments of the Federal share. This issue is more fully addressed in the discussion of § 50.54 below.

E. Loss Certifications (Section 50.53)

The final rule specifies the type of loss information that an insurer is required to submit in documenting insured losses eligible for payment of the Federal share of compensation. An Initial Certification of Loss, on a form prescribed by Treasury, is required when insured losses first exceed the insurer's deductible. If the insurer sustains ongoing, additional insured losses, periodic Supplementary Certifications of Loss, on a form prescribed by Treasury, must be submitted. These Certifications of Loss will be used by Treasury to assess payment eligibility for the Federal share of compensation and compliance with the Act's prerequisites for payment. The rule also addresses various written certifications the Act requires as a condition for payment of the Federal share. Specific statements certifying actions by the insurer as required by the Act, and by Treasury in administering and implementing the Act, are to be included as part of each Certification of Loss.

One revision to the proposed rule has been made to this section solely to add clarity. The definition of a bordereau, formerly § 50.53(e), has now been included in § 50.53(b)(1).

1. Timing of Submission of Initial Certification of Loss

In § 50.53(b) of the proposed rule, Treasury proposed that an insurer "use its best efforts to file the Initial Certification of Loss with Treasury within 45 days following the last calendar day of the month when an insurer's aggregate insured losses exceed its insurer deductible." One insurer trade organization commented that an insurer may not be able to file the initial certification of loss within that time period and that a time requirement is not really necessary. Alternatively, it suggested that Treasury modify the rule to allow insurers to request an extension of time to submit the Initial Certification of Loss.

The proposed rule provided for insurers to use their "best efforts" to submit the Initial Certification of Loss within 45 days. The proposed rule did not establish a fixed deadline that would serve as the basis to deny a claim for federal payment. Thus, a special request for an extension of time is not necessary so long as the insurer has used its best efforts to meet the requirement. Treasury believes this is reasonable. The objective of the rule is to encourage timely reporting of losses so that Treasury remains as current as possible with its potential liabilities. Generally, it will be in the insurer's interest to report losses as soon as possible. Accordingly, Treasury has made no change to the proposed rule.

The trade group also recommended that the loss certification process should specifically recognize special circumstances associated with large deductible policies. The commenter noted that with large deductible policies, particularly in workers compensation, insurers will typically first pay the entire claim to the insured worker and then recover the deductible from the insured employer. Treasury agrees that this comment regarding large deductible policies merits attention and will address the concern in the development of the actual loss certification reporting forms.

2. Certification Language

Two insurance trade associations and an insurer commented on the certification required in proposed rule § 50.53(b)(2)(iv) dealing with the clear and conspicuous disclosures that insurers are required to provide to policyholders. The commenters noted that the certification requirement appeared to impose a more stringent standard than was promulgated in previously issued regulations, in that insurers are required to certify they have "complied with the disclosure requirements * * * for each underlying loss." They suggested the use of less demanding certification language that would allow insurers to rely on "systems and normal business practices that demonstrate a practice of compliance" with the mandatory disclosure requirement as referenced in § 50.12(e).

Treasury does not believe that the compliance language of § 50.53(b)(2)(iv) is inconsistent or more stringent than the "normal business practices" approach in § 50.12(e). The compliance language of § 50.53(b)(2)(iv) means that for each underlying loss an insurer would be able to demonstrate it made an individual disclosure because it had a reliable system in its normal business practice that generated disclosures. For this reason, Treasury has decided to not change the certification language of § 50.53(b)(2)(iv).

One insurance trade association suggested deletion of the requirement in § 50.53(b)(2)(v) of the proposed rule to certify compliance with the Act's mandatory availability requirements because, in the commenter's view, there is no specific statutory requirement for the certification as a condition for payment. The mandatory availability or "make available" provisions in section 103(c) of the Act require that, for Program Years 1 and 2, and if so determined by Treasury for Program Year 3, all insurers must make available in all of their property and casualty insurance policies coverage for insured losses resulting from an act of terrorism. This coverage cannot differ materially from the terms, amounts, and other coverage limitations applicable to losses arising from events other than acts of terrorism. Under its authority in section 104(a)(2) of the Act to effectively administer and implement the Program, Treasury believes it is appropriate to include the certification requirement in § 50.53(b)(2)(iv). The "make available" requirement is, as the commenter also acknowledged, an "important predicate to the proper functioning of [the Act]." For this reason, Treasury has made no change in making the rule final.

3. State Residual Market Mechanisms

As described earlier, Treasury revised § 50.50(a)(2) of the proposed rule to clarify that the proportionate share of insured losses from State residual market insurance entities or State workers' compensation funds described in § 50.35 (those that share profit and losses) are treated as the insured losses of the individual insurer participants of those State residual market mechanisms. Joint comments from the four insurer trade associations also raised issues regarding the certification of loss requirements for these entities in § 50.53(b)(2) of the proposed rule. The joint comments observed that the flow of information pertaining to insured losses of State residual market mechanisms was different than that of individual insurers. For example, commenters noted that knowledge about processing claims in accordance with "appropriate business practices" as required by section 103(b)(3) of the Act lies with State residual market mechanism servicing carriers and administrators, not the participating insurers who are assessed a proportionate share of insured losses of the State residual market mechanism. Consequently, the joint trade association comment recommended special treatment for the loss certification requirements of § 50.53(b)(2) for State residual market insurance entities and State workers' compensation funds.

After considering the joint comments, as well as its own concerns with the mechanisms of information flow and content in connection with reconciling and auditing insured loss information of State residual market mechanisms, Treasury has added a new § 50.53(e) to the final rule to deal with loss certifications of State residual market mechanisms. Essentially, Treasury has sought to accommodate the special circumstances of State residual market mechanisms by separating the entity receiving payment (insurers participating in a residual market mechanism) from the entity with responsibility for providing certifications under section 103(b) of the Act (the residual market mechanism based on its own servicing or that of a servicing carrier).

In order to receive payment of the Federal share of compensation for residual market losses, an insurer participating in a State residual market mechanism will submit to Treasury, as an underlying loss on its bordereau, the amount of losses allocated to it by the State residual market mechanism. The State residual market mechanism will provide to its participating insurers the detailed underlying loss information that supports the total amount of insured losses from which the proportionate share of insured losses was calculated for each participating insurer. The State residual market mechanism will also provide to its participating insurers and to Treasury the certifications required by §§ 50.53(b)(2) and 50.53(c)(2). To facilitate any needed review or audit pursuant to §§ 50.60 and 50.61, State residual market mechanisms and their individual participating insurers are both required to maintain insured loss information they received or provided, as well as any supporting documentation for certifications.

F. Payment of Federal Share of Compensation (Section 50.54)

The final rule establishes the process for making payment as provided by the Act. It also addresses the making of payments before the total amount of insured losses are known, providing for later adjustment based on any overpayment or underpayment. The rule specifies the types of insurer accounts required for Treasury to electronically transfer funds in making payments of the Federal share of compensation and, in the case of advance payments of the Federal share, establishes that interest earned on those funds must be remitted to Treasury. Because the Act requires insurance entities within an affiliated group to be treated as a single entity in determining the insurer deductible, the rule requires that all payments be made to a single insurance entity within an affiliated group. This entity is to be identified by the affiliated group and designated on the Initial Notice of Insured Loss. Applicable payment process procedures are to be posted at www.treasury.gov/trip or otherwise made publicly available.

1. Prompt Payment

Section 50.54(a) of the proposed rule provided that Treasury would "promptly" pay to an insurer the Federal share of compensation due the insurer for its insured losses and that any overpayments by Treasury of the Federal share will be offset from future payments to the insurer or returned to Treasury within 45 days. Three comments were received on the issue of prompt payment. One commenter was pleased with the rule as written. Two commenters asked that prompt payment be better defined. One of these commenters suggested that Treasury set a goal of processing and paying claims within 45 days of receipt of an Initial Certification of Loss or any Supplemental Certification if the losses being claimed are not in dispute. After considering these comments, Treasury does not believe a regulatory time limit for payment is necessary. Treasury intends to pay the Federal share of compensation due insurers as promptly as possible and believes this commitment in the provision of public funds is sufficient. In seeking contractor support for the management of Program claims, Treasury has made this intention clear. Treasury has also clarified this section to specify that the payment process incorporates the use of electronic funds transfer through the Automated Clearinghouse (ACH) network. This provides a mechanism for the prompt disbursement of funds from Treasury to an insurer.

2. Advance Payments

As stated in the discussion of § 50.50, Treasury has revised this section in order to permit advance payments of the Federal share. Section 50.54 of the final rule describes the types of accounts required to be established by insurers to receive the Federal share of compensation. Treasury's control over the payment process is facilitated by having only one account per insurer into which payments will be made. If an insurer is only seeking reimbursement for insured losses it has already paid, then the only requirement for the account is the capability to receive electronic funds transfers over the ACH network. If an insurer seeks advance payments of the Federal share, or a combination of advance payments and reimbursement, then the account must be segregated from other insurer accounts. A "segregated account" is defined in section 50.54(d) of the final rule as an interest bearing, separate account at an institution eligible to receive payments through the ACH network and limited to the purposes of (i) receiving payments of the Federal share of compensation (ii) disbursing payments to insureds and claimants and (iii) transferring payments to the insurer or affiliated insurers for insured losses reported on the bordereau as already paid.

Payments to insureds and claimants that are made using funds advanced by Treasury are to be made directly from the segregated account. All interest earned on these advanced funds is to accrue through such time that payments from the account clear and is to be entirely remitted to Treasury. If it is determined that an insurer has not properly disbursed advances of the Federal share or otherwise not complied with these regulatory claims procedures, then Treasury may deny or withhold making advance payments of the Federal share of compensation.

3. Affiliated Group

Because the Act requires insurance entities within an affiliated group to be treated as a single entity in determining the insurer deductible, the proposed rule required that all payments be made to a single insurance entity within an affiliated group. The proposed rule required this entity to be identified by the affiliated group and designated on the Initial Notice of Insured Loss. The proposed rule further required insurers within an affiliated group to assign their rights to receive payments of their Federal share of compensation to this designated single insurance entity, while requiring the single insurance entity to distribute such payments "as appropriate" among affiliated insurers in the group.

Four commenters addressed issues involving Treasury's payment of the Federal share of compensation to a single insurance entity on behalf of an affiliated group of insurers. One commenter expressed the view that it preferred that Federal payments go to the individual insurer making the underlying claim payment. In the alternative, the commenter recommended that, in order to prevent a designated insurer from withholding distribution to affiliates, at a minimum, the rule be revised to require the single insurance entity to distribute payments of the Federal share of compensation to affiliated insurers in the group or to hold those funds in trust for distribution to affiliated insurers in the group. This suggestion was echoed by a second commenter.

Another commenter criticized the assignment requirement in § 50.54(c) of the proposed rule. Because of the potential shift in statutory rights or corporate asset values resulting from this "compulsory assignment of rights," the commenter suggested a better approach would be to require each entity within an affiliated group to appoint a common agent within the group for submission of claims while retaining legal title in its own name to all proceeds. The commenter further suggested that the common agent be required to act in a fiduciary capacity on behalf of other affiliates.

A fourth commenter noted that the execution of assignment agreements will trigger holding company filing requirements pursuant to state insurance laws. The commenter observed that such filing requirements have been brought to the attention of the NAIC and expressed interest in working with both NAIC and Treasury "to craft an appropriate solution that will be convenient for all parties." As a result of this comment, Treasury consulted with the NAIC and devised a more flexible approach to the single payee/affiliated group provision than what was proposed.

In the final rule, Treasury has deleted the requirement that affiliated insurers assign their rights to be paid under the Program to the single insurance entity in their affiliated group. Treasury has concluded that the proposed requirement of an assignment of rights may be an overly restrictive approach and that different mechanisms may be used among affiliate groups to assure proper distribution of the Federal share of compensation.

In addition, in § 50.54 of the final rule Treasury has clarified that the designated insurer receiving payments of the Federal share of compensation on behalf of an affiliated group must distribute payments in a manner that assures that other insurers in the group are compensated for their insured losses taking into account a reasonable and fair allocation of the group's insurer deductible. Because the insurer deductible for a group is an aggregate calculation based on the collective property and casualty insurance premium of all insurers in the group, Treasury recognizes there may be complexities and difficulties in determining individual insurer deductibles within the group. Treasury has thus provided guidance in requiring that the group deductible be allocated in a "reasonable and fair" manner among affiliated insurers. If necessary, Treasury will review the deductible allocation of an affiliated group, looking to the totality of the circumstances in determining what is "reasonable" and "fair." The final rule also clarifies that Treasury's obligation to pay the Federal share of compensation to affiliated insurers in a group is discharged upon its payment to the designated insurer, to the extent of the payment for insured losses of the group as reported on the group's bordereau. This provision does not prevent Treasury from subsequently adjusting payments, for example, as a result of an audit.

G. Audit Authority and Recordkeeping (Sections 50.60 and 50.61)

Sections 50.60 and 50.61 of the final rule require insurers to retain all records and files pertaining to the processing, handling, and settlement of insured losses, including electronic documents and data, and allow Treasury access in order to conduct subsequent financial, claims, and performance reviews and audits. Treasury and/or its appointed designee(s) will need access to pertinent books, files, agreements and records that support the insurer's Certifications of Loss previously submitted.

Three comments were received regarding the proposed §§ 50.60 Audit authority and 50.61 Recordkeeping. One commenter recommended that § 50.60 explicitly require the retention of reinsurance and other relevant agreements and that they be available during audit. Treasury believes that the proposed language already required such information to be maintained and accessible. Thus, no change to the proposed rule was required. A second commenter requested that access to the records be provided "upon reasonable notice" to the insurer by Treasury. Treasury has added this language to the final rule. This commenter also recommended that the audit authority of § 50.60 be expressly limited to the records required to be kept under § 50.61. Treasury disagrees and declines to limit the records it may need to access during investigation, audit and examination.

A third commenter was concerned with the type and form of claims records to be maintained. The commenter observed that § 50.61 of the proposed rule only required that "records" of material matters pertinent to insured losses be retained, not actual claim files containing activities relative to the handling and adjustment of claims. The commenter further suggested that any records required to be retained beyond actual claim files be permitted to be stored in a limited form such as electronic data storage Treasury is concerned with the availability of information needed for investigation, confirmation, audit and examination for the time periods specified in § 50.61, not the medium in which information is retained. Information that is material needs to be retained in whatever form that can provide reasonable access by Treasury. Treasury believes that insurers' normal claims and other record keeping methods, technology, and systems can be used to meet this requirement and the proposed rule does not need to be changed.

H. Other Issues

1. Future Issues

As Treasury explained in the preamble to the proposed rule, its strategy has been to give priority to regulations needed in the event of an act of terrorism. In addition to comments on the proposed claims rule, Treasury received several comments regarding aspects of insured losses resulting from certified acts of terrorism that were not included in the proposed rule. Comments were received concerning insurer insolvency, dispute resolution, commutation of losses, and the impact of losses exceeding the annual aggregate cap of $100 billion specified by the Act. These are the types of secondary issues that Treasury intends to address as necessary through guidance or supplementary rulemaking. Treasury will consider all the comments that have already been submitted in its development of pertinent future regulations.

2. Confidential or Privileged Information

A trade association commented that the proposed rule did not protect confidential or privileged information submitted to Treasury as part of the TRIA claim process. Any issues relating to the disclosure of confidential or privileged information will be addressed through the procedures and exceptions applicable under the Freedom of Information Act, 5 U.S.C. 552.

3. Longshore and Harbor Workers' Compensation Act Assessments

A comment, received from an insurer, dealt specifically with the insurer's situation regarding assessments under the Longshore and Harbor Workers' Compensation Act. This comment was not pertinent to the proposed rule and therefore has not been addressed. Insurers can request interpretations from Treasury pursuant to 31 CFR 50.9.

III. Procedural Requirements

Executive Order 12866, "Regulatory Planning and Review." This rule is a significant regulatory action for purposes of Executive Order 12866, "Regulatory Planning and Review," and has been reviewed by the Office of Management and Budget (OMB).

Regulatory Flexibility Act. Pursuant to the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*, it is hereby certified that this rule will not have a significant economic impact on a substantial number of small entities. Treasury is required to pay the Federal share of compensation to insurers for insured losses in accordance with the Act. A condition of Federal payment is that the insurer must submit to Treasury, in accordance with procedures established by Treasury, a claim for payment and certain certifications. The rule seeks to emulate loss reporting practices in the reinsurance industry, which insurers already follow in order to get payment for reinsurance, thus minimizing the impact on all insurers. The Act itself requires all insurers receiving direct earned premium for any type of property and casualty insurance, as defined in the Act, to participate in the Program. This includes all insurers regardless of size or sophistication. The Act also defines property and casualty insurance to mean commercial lines insurance without any reference to the size or scope of the insurer or the insured. Accordingly, any economic impact associated with the rule flows from the Act and not the rule. A regulatory flexibility analysis is thus not required.

Paperwork Reduction Act. The collection of information (recordkeeping requirement) contained in this rule has been approved by the OMB in accordance with the requirements of the Paperwork Reduction Act, 44 U.S.C. 3507(d) and assigned OMB Control Number 1505–0197. The forms to be prescribed by Treasury will be the subject of a separate submission to OMB on which the public will be provided an opportunity to comment. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid control number assigned by OMB.

The collection of information is the recordkeeping requirement in § 50.61. The information will be used by Treasury (or its designees) to audit or examine claims for Federal payments submitted by insurers. The recordkeeping requirement is mandatory for any insurer that seeks payment of a Federal share of compensation.

The estimated number of record keepers is 100 insurers sustaining insured losses. The estimated average annual burden per recordkeeper is 8.33 hours. The estimated total annual recordkeeping burden is 833 hours.

Comments regarding the accuracy of this burden estimate should be directed to the Terrorism Risk Insurance Program, Suite 2100, Department of the Treasury, 1425 New York Ave., NW., Washington, DC 20220 and to the Office of Management and Budget, Attn: Desk Officer for the Department of the Treasury, Office of Information and Regulatory Affairs, New Executive Office Building, Room 3208, Washington, DC 20503.

List of Subjects in 31 CFR Part 50

Terrorism risk insurance.

■ For the reasons stated above, 31 CFR part 50 is amended as follows:

PART 50—TERRORISM RISK INSURANCE PROGRAM

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

Authority: 5 U.S.C. 301; 31 U.S.C. 321; title I, Pub. L. 107–297, 116 Stat. 2322 (15 U.S.C 6701 note).

■ 2. Revise § 50.5(e) to read as follows:

§ 50.5 Definitions.

* * * * *

(e) *Insured loss.* (1) The term insured loss means any loss resulting from an act of terrorism (including an act of war, in the case of workers' compensation) that is covered by primary or excess property and casualty insurance issued by an insurer if the loss:

(i) Occurs within the United States;

(ii) Occurs to an air carrier (as defined in 49 U.S.C. 40102), to a United States flag vessel (or a vessel based principally in the United States, on which United States income tax is paid and whose insurance coverage is subject to regulation in the United States), regardless of where the loss occurs; or

(iii) Occurs at the premises of any United States mission.

(2)(i) A loss that occurs to an air carrier (as defined in 49 U.S.C. 40102), to a United States flag vessel, or a vessel based principally in the United States, on which United States income tax is paid and whose insurance coverage is subject to regulation in the United States, is not an insured loss under section 102(5)(B) of the Act unless it is incurred by the air carrier or vessel outside the United States.

(ii) An insured loss to an air carrier or vessel outside the United States under section 102(5)(B) of the Act does not include losses covered by third party insurance contracts that are separate from the insurance coverage provided to the air carrier or vessel.

(3) The term insured loss includes reasonable loss adjustment expenses, incurred by an insurer in connection with insured losses, that are allocated and identified by claim file in insurer records, including expenses incurred in the investigation, adjustment and defense of claims, but excluding staff salaries, overhead, and other insurer expenses that would have been incurred notwithstanding the insured loss.

(4) The term insured loss does not include:

(i) Punitive or exemplary damages awarded or paid in connection with the Federal cause of action specified in section 107(a)(1) of the Act. The term "punitive or exemplary damages" means damages that are not compensatory but are an award of money made to a claimant solely to punish or deter; or

(ii) Extra contractual damages awarded against, or paid by, an insurer; or

(iii) Payments by an insurer in excess of policy limits.

* * * * *

■ 3. New Subparts F and G of Part 50 are added as follows:

Subpart F—Claims Procedures

Sec.

Subpart F—Claims Procedures

§ 50.50 Federal share of compensation.

(a) *General.* The Treasury will pay the Federal share of compensation for insured losses as provided in section 103 of the Act once a Certification of Loss required by § 50.53 is deemed sufficient. Subject to paragraph (b) of this section, Treasury shall pay the appropriate amount of the Federal share of compensation upon a determination that:

(1) The insurer is an entity, including an affiliate thereof, that meets the requirements of § 50.5(f);

(2) The insurer's insured losses as defined in § 50.5(e), including the allocated dollar value of the insurer's proportionate share of insured losses from a State residual market insurance entity or State workers' compensation fund as described in § 50.35, have exceeded its insurer deductible as defined in § 50.5(g);

(3) The insurer has paid or is prepared to pay an underlying insured loss, based on a filed claim for the insured loss;

(4) Neither the insurer's claim for Federal payment nor any underlying claim for an insured loss is fraudulent, collusive, made in bad faith, dishonest or otherwise designed to circumvent the purposes of the Act and regulations;

(5) The insurer had provided a clear and conspicuous disclosure as required by §§ 50.10 through 50.19;

(6) The insurer took all steps reasonably necessary to properly and carefully investigate the underlying insured loss and otherwise processed the underlying insured loss using appropriate insurance business practices;

(7) The insured losses submitted for payment are within the scope of coverage issued by the insurer under the terms and conditions of the policies for commercial property and casualty insurance as defined in § 50.5(l); and

(8) The procedures specified in this Subpart have been followed and all conditions to payment have been met.

(b) *Adjustments.* Treasury may subsequently adjust, including requiring repayment of, any payment made under paragraph (a) of this section in accordance with its authority under the Act.

(c) *Suspension of payment for other insured losses.* Upon a determination by Treasury that an insurer has failed to meet any of the requirements for payment specified in paragraph (a) of this section for a particular insured loss, Treasury may suspend payment of the Federal share of compensation for all other insured losses of the insurer pending investigation and audit of the insurer's insured losses.

(d) *Amount payable.* The Federal share of compensation under the Program shall be 90 percent of that portion of the insurer's aggregate insured losses that exceed its insurer deductible during a Program Year, subject to any adjustments in § 50.51 and the cap of $100 billion as provided in section 103(e)(2) of the Act.

§ 50.51 Adjustments to the Federal share of compensation.

(a) *Aggregate amount of insured losses.* The aggregate amount of insured losses of an insurer in a Program Year used to calculate the Federal share of compensation shall be reduced by any amounts recovered by the insurer as salvage or subrogation for its insured losses in the Program Year.

(b) *Amount of Federal share of compensation.* The Federal share of compensation shall be adjusted as follows:

(1) *No excess recoveries.* For any Program Year, the sum of the Federal share of compensation paid by Treasury to an insurer and the insurer's recoveries for insured losses from other sources shall not be greater than the insurer's aggregate amount of insured losses for acts of terrorism in that Program Year. Amounts recovered for insured losses in excess of an insurer's aggregate amount of insured losses in a Program Year shall be repaid to Treasury within 45 days after the end of the month in which total recoveries of the insurer, from all sources, become excess. For purposes of this paragraph, amounts recovered from a reinsurer pursuant to an agreement whereby the reinsurer's right to any excess recovery has priority over the rights of Treasury shall not be considered a recovery subject to repayment to Treasury.

(2) *Reduction of amount payable.* The Federal share of compensation for insured losses under the Program shall be reduced by the amount of other compensation provided by other Federal programs to an insured or a third party to the extent such other compensation duplicates the insurance indemnification for those insured losses.

(i) *Other Federal program compensation.* For purposes of this section, compensation provided by other Federal programs for insured losses means compensation that is provided by Federal programs established for the purpose of compensating persons for losses in the event of emergencies, disasters, acts of terrorism, or similar events. Compensation provided by Federal programs for insured losses excludes benefit or entitlement payments, such as those made under the Social Security Act, under laws administered by the Secretary of Veteran Affairs, railroad retirement benefit payments, and other similar types of benefit payments.

(ii) *Insurer due diligence.* Each insurer shall inquire of each of its policyholders, insureds, and claimants whether the person receiving insurance proceeds for an insured loss has received, expects to receive, or is entitled to receive compensation from another Federal program for the insured loss, and if so, the source and the amount of the compensation received or expected. The response, source, and such amounts shall be reported with each underlying claim on the bordereau specified in § 50.53(b)(1).

§ 50.52 Initial Notice of Insured Loss.

Each insurer shall submit to Treasury an Initial Notice of Insured Loss, on a form prescribed by Treasury, whenever the insurer's aggregate insured losses (including reserves for "incurred but not reported" losses) within a Program Year exceed an amount equal to 50 percent of the insurer's deductible as specified in § 50.5(g). Insurers are advised the form for the Initial Notice of Insured Loss will include an initial estimate of aggregate losses for the Program Year, the amount of the insurer deductible and an estimate of the Federal share of compensation for the insurer's aggregate insured losses. In the case of an affiliated group of insurers, the form for the Initial Notice of Insured Loss will include the name and address of a single designated insurer within the affiliated group that will serve as the single point of contact for the purpose of providing loss and compliance certifications as required in § 50.53 and for receiving, disbursing, and distributing payments of the Federal share of compensation in accordance with § 50.54. An insurer, at its option, may elect to include with its Initial Notice of Insured Loss the certification of direct earned premium required by § 50.53(b)(3).

§ 50.53 Loss certifications.

(a) *General.* When an insurer has paid aggregate insured losses that exceed its insurer deductible, the insurer may make claim upon Treasury for the payment of the Federal share of compensation for its insured losses. The insurer shall file an Initial Certification of Loss, on a form prescribed by Treasury, and thereafter such Supplementary Certifications of Loss, on a form prescribed by Treasury, as may be necessary to receive payment for the Federal share of compensation for its insured losses.

(b) *Initial Certification of Loss.* An insurer shall use its best efforts to file with the Program the Initial Certification of Loss within 45 days following the last calendar day of the month when an insurer has paid aggregate insured losses that exceed its insurer deductible. The Initial Certification of Loss will include the following:

(1) A bordereau, on a form prescribed by Treasury, that includes basic information about each underlying insured loss. For purposes of this section, a "bordereau" is a report of basic information about an insurer's underlying claims that, in the aggregate, constitute the insured losses of the insurer. The bordereau will include, but, may not be limited to:

(i) A listing of each underlying insured loss by catastrophe code and line of business;

(ii) The total amount of reinsurance recovered from other sources;

(iii) A calculation of the aggregate insured losses sustained by the insurer above its insurer deductible for the Program Year; and

(iv) The amount the insurer claims as the Federal share of compensation for its aggregate insured losses.

(2) A certification that the insurer is in compliance with the provisions of section 103(b) of the Act and this part, including certifications that:

(i) The underlying insured losses listed on the bordereau filed pursuant to § 50.53(b)(1) either: Have been paid by the insurer; or will be paid by the insurer upon receipt of an advance payment of the Federal share of compensation as soon as possible, consistent with the insurer's normal business practices, but not longer than five business days after receipt of the Federal share of compensation;

(ii) The underlying claims for insured losses were filed by persons who suffered an insured loss, or by persons acting on behalf of such persons;

(iii) The underlying claims for insured losses were processed in accordance with appropriate business practices and the procedures specified in this subpart;

(iv) The insurer has complied with the disclosure requirements of §§ 50.10 through 50.19 for each underlying insured loss that is included in the amount of the insurer's aggregate insured losses; and

(v) The insurer has complied with the mandatory availability requirements of §§ 50.20 through 50.24.

(3) A certification of the amount of the insurer's "direct earned premium" as defined in § 50.5(d), together with the calculation of its "insurer deductible" as defined in § 50.5(g) (provided this certification was not submitted previously with the Initial Notice of Insured Loss specified in § 50.52).

(4) A certification that the insurer will disburse payment of the Federal share of compensation in accordance with this subpart.

(c) *Supplementary Certification of Loss.* If the total amount of the Federal share of compensation due an insurer for insured losses under the Act has not been determined at the time an Initial Certification of Loss has been filed, the insurer shall file monthly, or on a schedule otherwise determined by Treasury, Supplementary Certifications of Loss updating the amount of the Federal share of compensation owed for the insurer's insured losses. Supplementary Certifications of Loss will include the following:

(1) A bordereau described in § 50.53(b)(1); and

(2) A certification as described in § 50.53(b)(2).

(d) *Supplementary information.* In addition to the information required in paragraphs (b) and (c) of this section, Treasury may require such additional supporting documentation as required to ascertain the Federal share of compensation for the insured losses of any insurer.

(e) *State Residual Market Insurance Entities and State Workers' Compensation Funds.* A State residual market insurance entity or State workers' compensation fund described in § 50.35 shall provide the Certifications of Loss described in §§ 50.53(b) and 50.53(c) for all its insured losses to each participating insurer at the time it provides the allocated dollar value of the participating insurer's proportionate share of insured losses. In addition, at such time the State residual market insurance entity or State workers' compensation fund shall provide the certification described in § 50.53(b)(2) to Treasury. Participating insurers shall treat the allocated dollar value of their proportionate share of insured losses from a State residual market insurance entity or State workers' compensation fund as an insured loss for the purpose of their own reporting to Treasury in seeking the Federal share of compensation.

§ 50.54 Payment of Federal share of compensation.

(a) *Timing.* Treasury will promptly pay to an insurer the Federal share of compensation due the insurer for its insured losses. Payment shall be made in such installments and on such conditions as determined by the Treasury to be appropriate. Any overpayments by Treasury of the Federal share of compensation will be offset from future payments to the insurer or returned to Treasury within 45 days.

(b) *Payment process.* Payment of the Federal share of compensation for insured losses will be made to the insurer designated on the Initial Notice of Loss required by § 50.52. An insurer that requests payment of the Federal share of compensation for insured losses must receive payment through electronic funds transfer. The insurer must establish either an account for reimbursement as described in paragraph (c) of this section (if the insurer only seeks reimbursement) or a segregated account as described in paragraph (d) of this section (if the insurer seeks advance payments or a combination of advance payments and reimbursement). Applicable procedures will be posted at *www.treasury.gov/trip* or otherwise will be made publicly available.

(c) *Account for reimbursement.* An insurer shall designate an account for the receipt of reimbursement of the Federal share of compensation at an institution eligible to receive payments through the Automated Clearing House (ACH) network.

(d) *Segregated account for advance payments.* An insurer that seeks advance payments of the Federal share of compensation as certified according to § 50.53(b)(2)(i)(B) shall establish an interest-bearing segregated account into which Treasury will make advance payments as well as reimbursements to the insurer.

(1) *Definition of segregated account.* For purposes of this section, a segregated account is an interest-bearing separate account established by an insurer at a financial institution eligible to receive payments through the ACH network. Such an account is limited to the purposes of:

(i) Receiving payments of the Federal share of compensation;

(ii) Disbursing payments to insureds and claimants; and

(iii) Transferring payments to the insurer or affiliated insurers for insured losses reported on the bordereau as already paid.

(2) *Remittance of interest.* All interest earned on advance payments in the segregated account must be remitted at least quarterly to Treasury's Office of Financial Management or as otherwise prescribed in applicable procedures.

(e) *Denial or withholding of advance payment.* Treasury may deny or withhold advance payments of the Federal share of compensation to an insurer if Treasury determines that the insurer has not properly disbursed previous advances of the Federal share of compensation or otherwise has not complied with the requirements for advance payment as provided in this subpart.

(f) *Affiliated group.* In the case of an affiliated group of insurers, Treasury will make payment of the Federal share of compensation for the insured losses of the affiliated group to the insurer designated in the Initial Notice of Insured Loss to receive payment on behalf of the affiliated group. The designated insurer receiving payment from Treasury must distribute payment to affiliated insurers in a manner that ensures that each insurer in the affiliated group is compensated for its share of insured losses, taking into account a reasonable and fair allocation of the group deductible among affiliated insurers. Upon payment of the Federal share of compensation to the designated insurer, Treasury's payment obligation to the insurers in the affiliated group with respect to any insured losses covered on the applicable bordereau is discharged to the extent of the payment.

Subpart G—Audit and Investigative Procedures

§ 50.60 Audit authority.

The Secretary of the Treasury, or an authorized representative, shall have, upon reasonable notice, access to all books, documents, papers and records of an insurer that are pertinent to amounts paid to the insurer as the Federal share of compensation for insured losses for the purpose of investigation, confirmation, audit and examination.

§ 50.61 Recordkeeping.

Each insurer that seeks payment of a Federal share of compensation under subpart F of this part shall retain such records as are necessary to fully disclose all material matters pertinent to insured losses and the Federal share of compensation sought under the Program, including, but not limited to, records regarding premiums and insured losses for all commercial property and casualty insurance issued by the insurer and information relating to any adjustment in the amount of the Federal share of compensation payable. Insurers shall maintain detailed records for not less than 5 years from the termination dates of all reinsurance agreements involving commercial property and casualty insurance subject to the Act. Records relating to premiums shall be retained and available for review for not less than 3 years following the conclusion of the policy year. Records relating to underlying claims shall be retained for not less than 5 years following the final adjustment of the claim.

Dated: June 21, 2004.

Wayne A. Abernathy,

Assistant Secretary of the Treasury.

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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 JUNE 29, 2004

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National Oceanic and Atmospheric Administration

Fishery conservation and management:
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  - Pacific Coast groundfish; published 6-29-04

LABOR DEPARTMENT

Mine Safety and Health Administration

Coal mine safety and health:
- Surface and underground mines—
  - Definitions; technical amendments; published 6-29-04

TRANSPORTATION DEPARTMENT

Federal Aviation Administration

Airworthiness directives:
- Eurocopter France; published 6-14-04

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Cotton classing, testing and standards:
- Classification services to growers; 2004 user fees; Open for comments until further notice; published 5-28-04 [FR 04-12138]

AGRICULTURE DEPARTMENT

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- Highly pathogenic avian influenza; additional restrictions; comments due by 7-9-04; published 5-10-04 [FR 04-10524]

Plant-related quarantine, domestic:
- Karnal bunt; comments due by 7-6-04; published 5-5-04 [FR 04-10195]

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- Guaranteed farm ownership and operating loan requirements; comments due by 7-6-04; published 5-4-04 [FR 04-10068]

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AGRICULTURE DEPARTMENT

Rural Utilities Service

Rural Business Investment Program; administrative provisions; comments due by 7-8-04; published 6-8-04 [FR 04-12731]

RUS Telecommunications Borrowers; accounting requirements; comments due by 7-9-04; published 5-10-04 [FR 04-10512]

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  - Multispecies fishery; comments due by 7-6-04; published 6-21-04 [FR 04-13941]
- West Coast States and Western Pacific fisheries—
  - Pacific Coast groundfish; comments due by 7-7-04; published 6-7-04 [FR 04-12707]

COURT SERVICES AND OFFENDER SUPERVISION AGENCY FOR THE DISTRICT OF COLUMBIA

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Energy Efficiency and Renewable Energy Office

Consumer products; energy conservation program:
- Appliance standards program; possible expansion to include additional consumer products and commercial and industrial equipment; meeting; comments due by 7-9-04; published 4-30-04 [FR 04-09830]

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- Virginia Electric & Power Co. et al.; Open for comments until further notice; published 10-1-03 [FR 03-24818]

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- Hazardous waste combustors; comments due by 7-6-04; published 4-20-04 [FR 04-07858]

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  - Regional haze standards; best available retrofit technology determinations; implementation guidelines; comments due by 7-6-04; published 5-5-04 [FR 04-09863]

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- Idaho; comments due by 7-7-04; published 6-7-04 [FR 04-12700]
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- Harpin protein; comments due by 7-6-04; published 5-5-04 [FR 04-10212]

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- Montana; comments due by 7-6-04; published 6-1-04 [FR 04-12277]

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- Service-Disabled Veteran-Owned Small Business Concerns Procurement Program; comments due by 7-6-04; published 5-5-04 [FR 04-09752]

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LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. It may be used in conjunction with "P L U S" (Public Laws Update Service) on 202–741–6043. This list is also available online at *http://www.archives.gov/federal_register/public_laws/public_laws.html.*

The text of laws is not published in the **Federal Register** but may be ordered in "slip law" (individual pamphlet) form from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 (phone, 202–512–1808). The text will also be made available on the Internet from GPO Access at *http://www.gpoaccess.gov/plaws/index.html.* Some laws may not yet be available.

H.R. 1822/P.L. 108–239

To designate the facility of the United States Postal Service located at 3751 West 6th Street in Los Angeles, California, as the "Dosan Ahn Chang Ho Post Office". (June 25, 2004; 118 Stat. 673)

H.R. 2130/P.L. 108–240

To redesignate the facility of the United States Postal Service located at 121 Kinderkamack Road in River Edge, New Jersey, as the "New Bridge Landing Post Office". (June 25, 2004; 118 Stat. 674)

H.R. 2438/P.L. 108–241

To designate the facility of the United States Postal Service located at 115 West Pine Street in Hattiesburg, Mississippi, as the "Major Henry A. Commiskey, Sr. Post Office Building". (June 25, 2004; 118 Stat. 675)

H.R. 3029/P.L. 108–242

To designate the facility of the United States Postal Service located at 255 North Main Street in Jonesboro, Georgia, as the "S. Truett Cathy Post Office Building". (June 25, 2004; 118 Stat. 676)

H.R. 3059/P.L. 108–243

To designate the facility of the United States Postal Service located at 304 West Michigan Street in Stuttgart, Arkansas, as the "Lloyd L. Burke Post Office". (June 25, 2004; 118 Stat. 677)

H.R. 3068/P.L. 108–244

To designate the facility of the United States Postal Service located at 2055 Siesta Drive in Sarasota, Florida, as the "Brigadier General (AUS-Ret.) John H. McLain Post Office". (June 25, 2004; 118 Stat. 678)

H.R. 3234/P.L. 108–245

To designate the facility of the United States Postal Service located at 14 Chestnut Street in Liberty, New York, as the "Ben R. Gerow Post Office Building". (June 25, 2004; 118 Stat. 679)

H.R. 3300/P.L. 108–246

To designate the facility of the United States Postal Service located at 15500 Pearl Road in Strongsville, Ohio, as the "Walter F. Ehrnfelt, Jr. Post Office Building". (June 25, 2004; 118 Stat. 680)

H.R. 3353/P.L. 108–247

To designate the facility of the United States Postal Service located at 525 Main Street in Tarboro, North Carolina, as the "George Henry White Post Office Building". (June 25, 2004; 118 Stat. 681)

H.R. 3536/P.L. 108–248

To designate the facility of the United States Postal Service located at 210 Main Street in Malden, Illinois, as the "Army Staff Sgt. Lincoln Hollinsaid Malden Post Office". (June 25, 2004; 118 Stat. 682)

H.R. 3537/P.L. 108–249

To designate the facility of the United States Postal Service located at 185 State Street In Manhattan, Illinois, as the "Army Pvt. Shawn Pahnke Manhattan Post Office". (June 25, 2004; 118 Stat. 683)

H.R. 3538/P.L. 108–250

To designate the facility of the United States Postal Service located at 201 South Chicago Avenue in Saint Anne, Illinois, as the "Marine Capt. Ryan Beaupre Saint Anne Post Office". (June 25, 2004; 118 Stat. 684)

H.R. 3690/P.L. 108–251

To designate the facility of the United States Postal Service located at 2 West Main Street in Batavia, New York, as the "Barber Conable Post Office Building". (June 25, 2004; 118 Stat. 685)

H.R. 3733/P.L. 108–252

To designate the facility of the United States Postal Service located at 410 Huston Street in Altamont, Kansas, as the "Myron V. George Post Office". (June 25, 2004; 118 Stat. 686)

H.R. 3740/P.L. 108–253
To designate the facility of the United States Postal Service located at 223 South Main Street in Roxboro, North Carolina, as the "Oscar Scott Woody Post Office Building". (June 25, 2004; 118 Stat. 687)

H.R. 3769/P.L. 108–254
To designate the facility of the United States Postal Service located at 137 East Young High Pike in Knoxville, Tennessee, as the "Ben Atchley Post Office Building". (June 25, 2004; 118 Stat. 688)

H.R. 3855/P.L. 108–255
To designate the facility of the United States Postal Service located at 607 Pershing Drive in Laclede, Missouri, as the "General John J. Pershing Post Office". (June 25, 2004; 118 Stat. 689)

H.R. 3917/P.L. 108–256
To designate the facility of the United States Postal Service located at 695 Marconi Boulevard in Copiague, New York, as the "Maxine S. Postal United States Post Office". (June 25, 2004; 118 Stat. 690)

H.R. 3939/P.L. 108–257
To redesignate the facility of the United States Postal Service located at 14-24 Abbott Road in Fair Lawn, New Jersey, as the "Mary Ann Collura Post Office Building". (June 25, 2004; 118 Stat. 691)

H.R. 3942/P.L. 108–258
To redesignate the facility of the United States Postal Service located at 7 Commercial Boulevard in Middletown, Rhode Island, as the "Rhode Island Veterans Post Office Building". (June 25, 2004; 118 Stat. 692)

H.R. 4037/P.L. 108–259
To designate the facility of the United States Postal Service located at 475 Kell Farm Drive in Cape Girardeau, Missouri, as the "Richard G. Wilson Processing and Distribution Facility". (June 25, 2004; 118 Stat. 693)

H.R. 4176/P.L. 108–260
To designate the facility of the United States Postal Service located at 122 West Elwood Avenue in Raeford, North Carolina, as the "Bobby Marshall Gentry Post Office Building". (June 25, 2004; 118 Stat. 694)

H.R. 4299/P.L. 108–261
To designate the facility of the United States Postal Service located at 410 South Jackson Road in Edinburg, Texas, as the "Dr. Miguel A. Nevarez Post Office Building". (June 25, 2004; 118 Stat. 695)

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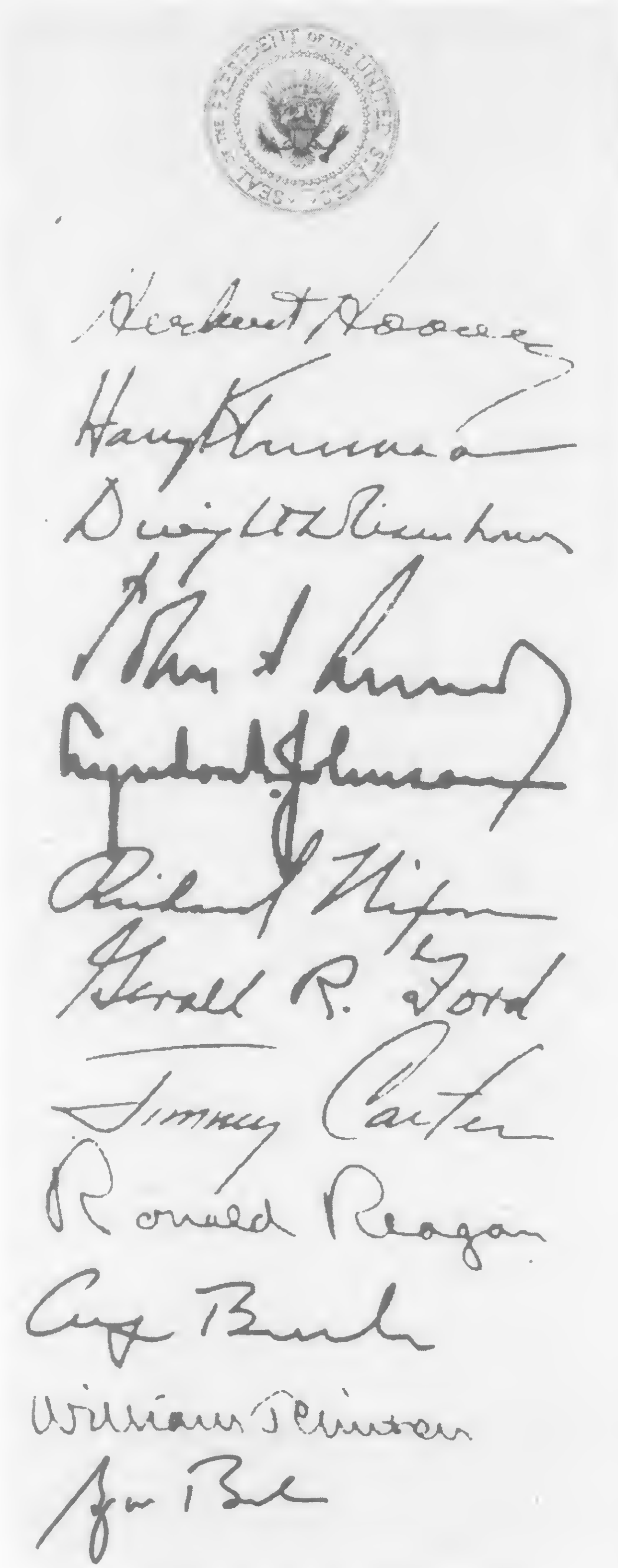

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