WEST VIRGINIA

SECRETARY OF STATE

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ADMINISTRATIVE LAW DIVISION

Form #3

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OFFICE OF WEST VIRGINIA SECRETARY OF STATE

NOTICE OF AGENCY APPROVAL OF A PROPOSED RULE
AND
FILING WITH THE LEGISLATIVE RULE-MAKING REVIEW COMMITTEE

AGENCY: DIVISION OF ENVIRONMENTAL PROTECTION OFFICE OF AIR QUALITY TITLE NUMBER: 45CSR33

CITE AUTHORITY WV CODE §§22-5-1 et seq.

AMENDMENT TO AN EXISTING RULE: YES X NO ___

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 45CSR33

TITLE OF RULE BEING AMENDED: ACID RAIN PROVISIONS AND PERMITS

IF NO, SERIES NUMBER OF NEW RULE BEING PROPOSED: ___

TITLE OF RULE BEING PROPOSED: ___

THE ABOVE PROPOSED LEGISLATIVE RULE HAVING GONE TO A PUBLIC HEARING OR A PUBLIC COMMENT PERIOD IS HEREBY APPROVED BY THE PROMULGATING AGENCY FOR FILING WITH THE SECRETARY OF STATE AND THE LEGISLATIVE RULE MAKING REVIEW COMMITTEE FOR THEIR REVIEW.

G. DALE FARLEY
CHIEF, OFFICE OF AIR QUALITY

25.00

45CSR33

ACID RAIN PROVISIONS AND PERMITS

STATEMENT OF CIRCUMSTANCES

Under the Acid Rain Program promulgated by the United States Environmental Protection Agency, pursuant to Title IV of the Clean Air Act, as amended, no person may construct, modify, or operate or cause to be constructed, modified, or operated, an Acid Rain source in violation of 40 CFR Part 72. Promulgation of this rule by the Legislature is necessary for the State to fulfill its responsibilities under the Clean Air Act, as amended.

45CSR33

ACID RAIN PROVISIONS AND PERMITS

Determination of Stringency

W. Va. Code §22-1-3 in conjunction with W. Va. Code §22-1-3a requires, in part, the Director of the Division of Environmental Protection, to determine if a new or amended environmental provision should be the same in substance as a counterpart federal regulation. If the new rule should be the same in substance, as the counterpart federal regulation, then the Director shall incorporate by reference, to the greatest extent possible, the federal counterpart rule. If the Director determines the rule should not be the same in substance as the federal counterpart rule, then the Director shall file a statement setting forth the difference between the proposed rule and the counterpart federal regulation. W. Va. Code §22-1-3a requires the Director to conduct the "stringency" determination and provide specific reasons for deviation of the proposed state rule from the federal counterpart regulation.

The Director has determined that this rule is no more or no less stringent than the federal counterpart rule, 40 CFR Part 72.

45CSR33

ACID RAIN PROVISIONS AND PERMITS

Private Real Property Protection Act Assessment

The Division of Environmental Protection is required to perform a "constitutional takings determination" or assessment in only limited circumstances (See "Private Real Property Protection Act", W. Va. Code §§22-1A-1 et seq.). Under W. Va. Code §22-1A-3(a), such an assessment is not required, unless the action being contemplated by the Division is reasonably likely to deprive a private real property owner of his or her property in fee simple or to deprive an owner of all productive use of his or her property.

W. Va. Code §22-1A-3(c) expressly exempts rulemaking which simply limits uses pursuant to statute from the assessment requirement. In pertinent part, Section 3(c) provides that the following actions do not require an assessment:

(1) Licensing or permitting conditions, requirements or limitations to the use of private real property pursuant to any applicable state or federal statutes, rules or regulations; or

(2) Rules and emergency rules of the division that are reasonably likely to limit the use of private real property pursuant to any applicable state or federal statutes, rules or regulations;

See W. Va. Code §22-1A-3(c)(1) and (2).

Therefore, since this is a rulemaking pursuant to statute, an assessment is not required.

45CSR33

ACID RAIN PROVISIONS AND PERMITS

Consultation with the Environmental Protection Advisory Council

West Virginia Code Section §22-1-3(c) requires, in part, the Director of the Division of Environmental Protection to consult with the Environmental Protection Advisory Council prior to proposing any new rule. This rule was filed prior to the appointment of the Environmental Protection Advisory Council, therefore, no consultation with the Environmental Protection Advisory Council has been possible.

APPENDIX B

FISCAL NOTE FOR PROPOSED RULES

Rule Title: 45CSR33 - Acid Rain Provisions and Permits

Type of Rule: __X__ Legislative _____ Interpretive _____ Procedural

Agency: Office of Air Quality

Address: 1558 Washington Street, East

Charleston, WV 25311-2599

1. Effect of Proposed Rule	Annual		Fiscal Year		
	Increase	Decrease	Current	Next	There-after
Estimated Total Cost	$ -0-	$ -0-	$ -0-	$ -0-	$ -0-
Personal Services	-0-	-0-	-0-	-0-	-0-
Current Expense	-0-	-0-	-0-	-0-	-0-
Repairs and Alterations	-0-	-0-	-0-	-0-	-0-
Equipment	-0-	-0-	-0-	-0-	-0-
Other	-0-	-0-	-0-	-0-	-0-

2. Explanation of above estimates: Costs incurred for implementation of this rule have been previously considered and are covered under the budget estimate for implementing Titles IV and V of the Clean Air Act, as amended, under 45CSR30 promulgated by the Legislature during the 1994 Session. The proposed rule amendments incorporate technical corrections and updates to the previously authorized rule and do not entail additional fiscal input.

3. Objectives of these rules: This rule establishes general provisions and the operating permit program requirements for affected sources and affected units under the Acid Rain Program promulgated by the United States Environmental Protection Agency under Title IV of the Clean Air Act, as amended.

4. Explanation of overall economic impact of proposed rule.

   A. Economic impact on state government.

      See Section 2.

   B. Economic impact on political subdivisions; specific industries; specific groups of citizens.

      No impact above that resulting from the currently applicable federal requirements.

   C. Economic impact on citizens/public at large.

      No impact above that resulting from the currently applicable federal requirements.

Date: June 14, 1995

Signature of agency head or authorized representative:

G. Dale Farley
Chief, Office of Air Quality

DATE: JULY 28, 1995

TO: LEGISLATIVE RULE-MAKING REVIEW COMMITTEE

FROM: DIVISION OF ENVIRONMENTAL PROTECTION, OFFICE OF AIR QUALITY

LEGISLATIVE RULE TITLE: 45CSR33 - "Acid Rain Provision and Permits"

1. Authorizing statute(s) citation W. Va. Code §§22-5-1 et seq.

2. a. Date filed in State Register with Notice of Hearing:

   June 14, 1995

   b. What other notice, including advertising, did you give of the hearing?

   Charleston Gazette and Charleston Daily Mail; Division of Environmental Protection and Office of Air Quality Mailing Lists; U. S. Environmental Protection Agency and surrounding affected states.

   c. Date of hearing(s): July 19, 1995

   d. Attach list of persons who appeared at hearing, comments received, amendments, reasons for amendments.

   Attached X No comments received ____

   e. Date you filed in State Register the agency approved proposed Legislative Rule following public hearing: (be exact)

   July 28, 1995

   f. Name and phone number(s) of agency person(s) to contact for additional information:

   G. Dale Farley, Chief, Office of Air Quality, (304) 558-2275

3. If the statute under which you promulgated the submitted rules requires certain findings and determinations to be made as a condition precedent to their promulgation:

a. Give the date upon which you filed in the State Register a notice of the time and place of a hearing for the taking of evidence and a general description of the issues to be decided.

N/A

b. Date of hearing: N/A

c. On what date did you file in the State Register the findings and determinations required together with the reasons therefor?

N/A

d. Attach findings and determinations and reasons:

Attached N/A

BUREAU OF ENVIRONMENT
10 McJunkin Road
Nitro, WV 25143-2506

GASTON CAPERTON
GOVERNOR

LAIDLEY ELI MCCOY, PH.D.
COMMISSIONER

July 21, 1995

Ms. Judy Cooper
Director, Administrative Law Division
Secretary of State's Office
Building 1, Suite 157K
Charleston, West Virginia 25305

RE: 45CSR33 - "Acid Rain Provisions and Permits"

Dear Ms. Cooper:

This is to advise you that I am giving approval for the filing of the above-captioned agency-approved rule with the Secretary of State's Office and Legislative Rule-Making.

Your cooperation in this regard is very much appreciated. If you have any questions or require additional information, please feel free to contact Roger T. Hall at 759-0515.

Sincerely yours,

Laidley Eli McCoy

Laidley Eli McCoy, Ph.D.
Commissioner

LEM;RTH:cc

Attachment

BUREAU OF ENVIRONMENT
10 McJunkin Road
Nitro, WV 25143-2506

GASTON CAPERTON
GOVERNOR

LAIDLEY ELI MCCOY, PH.D.
COMMISSIONER

June 19, 1995

Ms. Judy Cooper
Director, Administrative Law Division
Secretary of State's Office
Building 1, Suite 157K
Charleston, West Virginia 25305

RE: 45 CSR 33 - "Acid Rain Provisions and Permits"

Dear Ms. Cooper:

This is to advise you that I am giving approval for the filing of the above-captioned rule as a proposed amendment to an existing legislative rule.

Your cooperation in this regard is very much appreciated. If you have any questions or require additional information, please feel free to contact Roger T. Hall at 759-0515.

Sincerely yours,

Laidley Eli McCoy

Laidley Eli McCoy, Ph.D.
Director

LEM;RTH:cc

Attachment

45CSR33

ACID RAIN PROVISIONS AND PERMITS

SUMMARY

Title IV of the federal Clean Air Act, as amended, November 15, 1990, requires each state to implement an operating permit system conforming to Title IV and Title V. West Virginia complied by enacting rule 45 CSR 33 " Acid Rain Provisions and Permits" effective May 1, 1995. The United States Environmental Protection Agency is committed to approve West Virginia's Acid Rain Program contingent on a commitment by the State to change specific language in 45 CSR 33. These revisions meet that commitment and are in accordance with EPA's guidance. The following summarizes the changes:

- Section 45 - 33 - 5

  The entire section should be deleted. All authorities that can be delegated to West Virginia are denoted in 40 CFR Part 72 by the term "permitting authority." All authorities that cannot be delegated to West Virginia are denoted by the term "Administrator." Therefore, the term "Administrator" can never mean the "Director" or the West Virginia Division of Environmental Protection; it always means the Administrator of the United States Environmental Protection Agency.

- Section 45 - 33 - 6 Permits., and 45 - 33 - 7. Inconsistency Between Rules.

  40 CFR 72.70 (b) states that 40 CFR Part 72 takes precedence in the event of a conflict between a state's operating permits rule and 40 CFR 72 (for example, in matters pertaining to the issuance, denial, revision, reopening, renewal, and appeal of the acid rain portion of an operating permit). Other sections in Part 72 address specific points of potential conflict between Part 72 and a state's rules. For example, 72.9 (h) (1) states that the Acid Rain Program does not exempt an affected source from complying with any other requirement of the Clean Air Act (for example, Title I state implementation plan requirements). Conflicts between 40 CFR Part 72 and West Virginia's other rules are therefore resolved by the regulatory language in 40 CFR part 72, and not by "the determination of the Director." The language in previous 45 - 33 - 7 has been modified accordingly. Section 45 - 33 - 6 should be deleted since it states that the requirements of other rules apply in full despite any conflicts with the requirements of the West Virginia acid rain rule. This contradicts the new language of 45 - 33 - 7.

45CSR33

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OFFICE OF WEST VIRGINIA
SECRETARY OF STATE

TITLE 45
LEGISLATIVE RULE

BUREAU OF ENVIRONMENT
DIVISION OF ENVIRONMENTAL PROTECTION
OFFICE OF AIR QUALITY

SERIES 33
ACID RAIN PROVISIONS AND PERMITS

§45-33-1. General.

1.1 Scope. - This rule establishes general provisions and the operating permit program requirements for affected sources and affected units under the Acid Rain Program promulgated by the United States Environmental Protection Agency under Title IV of the Clean Air Act, as amended. It is the intent of the Director to adopt these standards by reference. It is also the intent of the Director to adopt associated reference methods, performance specifications and other test methods which are appended to these standards.

1.2. Authority. - W. Va. Code §§22-5-1 et seq.

1.3. Filing Date. - July 31, 1995

1.4. Effective Date. -

1.5. Incorporation by Reference - Federal Counterpart Regulation. - The Director has determined that a federal counterpart regulation exists, and in accordance with the Director's recommendation~~, with limited exceptions,~~ this rule incorporates by reference ~~(~~40 CFR Part 72~~)~~as in effect on June 1, 1995.

§45-33-2. Requirements.

2.1. No person may construct, modify, or operate or cause to be constructed, modified, or operated an Acid Rain source which results or will result in a violation~~s~~ of this rule.

§45-33-3. Definitions.

3.1 "Administrator" shall mean the Administrator of the United States Environmental Protection Agency.

3.2 "Director" shall mean the Director of the West Virginia Division of Environmental Protection or his or her designated representative.

3.3 "Permitting Authority" shall mean the West Virginia Division of Environmental Protection.

§45-33-4. Adoption of Standards.

4.1 The Director hereby adopts and incorporates by reference the provisions of 40 CFR Part 72, including associated reference methods, performance specifications and other test methods which are appended to such standards and contained in 40 CFR Part 72 as in effect on ~~July~~June 1, 1994~~4~~5, for the purposes of implementing an acid rain program that meets the requirements of Title IV of the federal Clean Air Act, as amended.

~~**§45-33-5. Director.**~~

~~5.1 Any and all references in said 40 CFR Part 72 to the "Administrator" is amended to be the "Director" except in the following references which shall remain "Administrator."~~

~~5.1.a. Part 72.2 pertaining to the definition of:~~

~~account number~~
~~acid rain emissions limitation~~
~~actual SO_2 emissions rate~~
~~administrator~~
~~allocate or allocation~~
~~allowance~~
~~allowance deduction~~
~~allowances held~~
~~allowance reserve~~
~~allowance tracking~~
~~allowance tracking system~~
~~alternative monitoring system~~
~~automated data acquisition and handling system~~
~~award~~
~~basic phase II allowance allocations~~
~~compliance certification~~
~~decisional body~~
~~emissions~~
~~EPA trial staff~~
~~future year subaccount~~
~~monitor operating hour~~
~~national allowance database~~
~~permitting authority~~

~~recordation~~
~~serial number~~
~~State operating permit program~~

~~5.1.b. Part 72.7(c)(2)(iii)~~

~~5.1.c. Part 72.8(c)(2)(iii)~~

~~5.1.d. Part 72.9(c)(6)~~

~~5.1.e. Part 72.9(c)(7)~~

~~5.1.f. Part 72.12~~

~~5.1.g. Part 72.30~~

~~5.1.h. Part 72.33~~

~~5.1.i. Part 72.41~~

~~5.1.j. Part 72.42~~

~~5.1.k. Part 72.43~~

~~5.1.l. Part 72.44(f)(3)~~

~~5.1.m. Part 72.44(g)(1)(ii)~~

~~5.1.n. Part 72.44(g)(2)~~

~~5.1.o. Part 72.44(g)(2)(iii)~~

~~5.1.p. Part 72 Subpart F~~

~~5.1.q. Part 72 Subpart G~~

~~5.1.r. Part 72.80~~

~~5.1.s. Part 72.81(c)(1)(i)~~

~~5.1.t. Part 72.83(b)~~

~~5.1.u. Part 72.84~~

~~5.1.v. Part 72.91(b)~~

~~5.1.w. Part 72.92~~

~~5.1.x. Part 72.96~~

~~**§45-33-6. Permits.**~~

~~Nothing contained in this rule shall be construed or inferred to mean that permit requirements in accordance with applicable rules shall be in any way be limited or inapplicable.~~

§45-33-~~7~~5. Inconsistency Between Rules.

~~In the event of any inconsistency between this rule and any other existing rule of the West Virginia Division of Environmental Protection, such inconsistency shall be resolved by the determination of the Director and such determination shall be based upon the application of the more stringent provision, term, condition, method, rule or regulation.~~The provisions of this rule shall not be construed as exempting persons subject to this rule from compliance with any other provisions of the Clean Air Act, including the provisions of Title I of the Clean Air Act relating to applicable National Ambient Air Quality Standards, the State Implementation Plan, or any other rules of the West Virginia Division of Environmental Protection, except as expressly provided under Title IV of the Clean Air Act; provided however, that in the event of any inconsistency between the provisions of this rule and any provisions of 45CSR30, the provisions of this rule shall take precedence and shall govern the issuance, denial, revision, reopening, renewal, and appeal of the Acid Rain provision of an operating permit.

federal register

Tuesday
April 11, 1995

Part IV

Environmental Protection Agency

Clean Air Act: Acid Rain Program Permits; Final Rule and Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 72

[FRL–5186–3]

RIN 2060–AE59

Acid Rain Program: Permits

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: Title IV of the Clean Air Act (the Act), as amended by the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The program sets emissions limitations to reduce acidic deposition and its serious, adverse effects on natural resources, ecosystems, materials, visibility, and public health. On January 11, 1993, the Agency promulgated final rules under title IV. Several parties filed petitions for review of the rules. On January 10, 1995, EPA and the parties signed a settlement agreement addressing reduced utilization issues.

Based on a review of the record, the Agency concludes that the January 11, 1993 regulations concerning reduced utilization should be revised. The overall effect of the revisions is to reduce the reporting and recordkeeping burden on utilities. The regulations require that, unless certain requirements are met, the designated representative of a unit in Phase I of the program whose annual utilization of fuel is less than its average annual utilization in 1985–1987 must submit a reduced utilization plan. The regulations also require designated representatives to submit end-of-year compliance reports that estimate the sulfur dioxide emissions resulting from any underutilization of Phase I units and to surrender allowances for the estimated emissions. The Agency is revising the regulations to simplify the criteria for determining if a reduced utilization plan must be submitted: Where the end-of-year reporting and allowance surrender requirements are met, such a plan is not required. Further, the Agency is revising the formulas for estimating emissions resulting from underutilization to correct errors, clarify certain provisions, and take account of and facilitate compliance by Phase I units with multiple owners or whose owners are required by law to purchase electricity from non-utility power production facilities.

The rule revision is being issued as a direct final rule because it is consistent with the January 10, 1995 settlement and no adverse comment is expected.

EFFECTIVE DATE: This direct final rule will be effective on May 22, 1995 unless significant, adverse comments are received by May 11, 1995. If significant, adverse comments are timely received on any portion of the direct final rule, that portion of the direct final rule will be withdrawn through a notice in the **Federal Register**.

ADDRESSES: All written comments must be identified with the appropriate docket number and must be submitted in duplicate to: EPA Air Docket Section (LE–131), Waterside Mall, Room 1500, 1st floor, 401 M St., S.W., Washington DC 20460.

Docket No. A–93–40, containing supporting information used to develop the proposal, copies of all comments received, and responses to comments, is available for public inspection and copying from 8:30 a.m. to 12:00 p.m. and 1:00 p.m. to 3:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section, Waterside Mall, Room 1500, 1st floor, 401 M St., S.W., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Dwight C. Alpern, Attorney-advisor, at (202) 233–9151, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St., S.W., Washington, DC 20460, or the Acid Rain Hotline at (202) 233–9620.

SUPPLEMENTARY INFORMATION: All public comment received on any portion of this direct final rule on which significant, adverse comments are timely received will be addressed in a subsequent final rule. That final rule will be based on the relevant portion of the rule revision that is noticed as a proposed rule in the Proposed Rules Section of this **Federal Register** and that is identical to this direct final rule. The contents of the preamble to the direct final rule are as follows:

I. Background: Purposes of Reduced Utilization Plans and Allowance Surrender for Underutilization of Phase I Units

A Phase I unit is underutilized if, in any year in Phase I, the total annual utilization of fuel at the unit is less than its baseline, i.e., its annual average fuel utilization for 1985–1987. The provisions of the Act that relate to reduced utilization or underutilization of Phase I units are found in sections 403(d) and 408(c)(1)(B).

In dividing the Acid Rain Program into two phases, i.e., Phase I applicable only to larger, dirtier units and Phase II applicable to virtually all utility units, the Congress recognized the potential for circumvention of Phase I emission reduction requirements. A Phase I unit, which receives allowances for its baseline, could simply reduce its utilization below baseline by shifting generation of electricity to a unit that was not covered by Phase I and did not have to use allowances to authorize its SO_2 emissions. The Phase I unit would retain the unused allowances but the same amount of SO_2 could be emitted by the second unit, which would not use up any allowances. See 58 FR 60951 (Nov. 18, 1993). In section 408(c)(1)(B), Congress adopted the solution of requiring submission of a reduced utilization plan by owners and operators of any Phase I unit that plans to reduce the unit's utilization in order to comply with Phase I emissions limitations. The plan must designate the units (referred to as "compensating units") to which generation was shifted or account for the reduced utilization through energy conservation or improved unit efficiency. 59 FR 60219 (Nov. 22, 1994).

Section 403(d) provides that the Acid Rain regulations must permit utilities to continue to operate in an economic and reliable fashion (e.g., through central dispatching that may result in shifting generation from Phase I units to other units or generators). However, section 403(d) also provides that the Acid Rain regulations must require utilities to compensate at the end of the year for emissions resulting from such operations and must facilitate orderly and competitive functioning of the allowance system. 56 FR 63019 (Dec. 3, 1991).

In order to achieve the objectives of both section 403(d) and section 408(c)(1)(B), EPA adopted, in the January 11, 1993 regulations, requirements concerning the submission of reduced utilization plans and allowance surrender for underutilization. The regulations require that the designated representative of any Phase I unit with utilization below baseline apply formulas in §§ 72.91 and 72.92 estimating the emissions (if any) resulting from such underutilization and surrender allowances covering the estimated emissions. In this way, the emissions consequences of shifting generation from Phase I units are accounted for, and Phase I SO_2 emission reduction goals are preserved, without the designation of specific compensating units.

In addition, the January 11, 1993 regulations require the submission of a reduced utilization plan for any Phase I unit that is planned to be utilized below baseline as a method of complying with SO_2 emissions limitations. However, if the allowance surrender requirements are met and the unit meets criteria in § 72.43(e), a plan is not required. The criteria are broadly drawn. For example, under these criteria, a plan need not be submitted for underutilization caused by economic dispatching that reflected increases in generation costs (e.g., allowance costs) at the unit. The Agency adopted this approach of limiting the plan submission requirement because of concern that, *inter alia*, economic dispatch and operation of utility systems or power pools might be inhibited because utilities might be unable to designate compensating units. 56 FR 63021.

II. Reduced Utilization Plans

As noted above, § 72.43(e) of the January 11, 1993 regulations sets forth criteria for making retrospective determinations as to whether a Phase I unit was underutilized for the purpose of complying with SO_2 emissions limitations. If underutilization was for the purpose of compliance, then the unit must have a reduced utilization plan. If underutilization was incidental to utility operations, no plan is needed. In particular, a plan is not required if the allowance surrender requirements under §§ 72.91 and 72.92 are met and one of several demonstrations are made. The demonstrations involve showing that the unit's underutilization was caused by a dispatch-system-wide sales decline, a forced outage at the unit, or economic dispatching. If none of these demonstrations can be made, the Agency determines on a case-by-case basis, considering certain indicators set forth in § 72.43(e)(2), whether a plan should have been submitted.

The Agency has concluded that this approach is unnecessarily complicated and burdensome. Because of concerns that Phase I units would be unable to designate compensating units, the criteria in § 72.43(e) for avoiding submission of a reduced utilization plan were designed to apply broadly. In particular, a plan is not required to the extent underutilization is caused by economic dispatching. Consequently, under these criteria, plan submission is largely optional so long as the allowance surrender requirements are met.

However, despite their broad scope, the criteria still leave some uncertainty as to whether the Agency will agree that a reduced utilization plan is not required even if allowances are surrendered. Further, owners and operators of Phase I units carry the burden of showing that the criteria are met. In fact, the January 11, 1993 regulations require Phase I unit owners and operators to show in their annual compliance certification reports the amounts of underutilization caused by sales decline, forced outage, or economic dispatching. 40 CFR 72.92(a)(2) (1993). The annual reports must also include specified information on forced outages at Phase I units. 40 CFR 72.92(a)(3) (1993). Additional submissions are required during the year in the event of a forced outage that will permanently shut down a Phase I unit and result in shifting generation to other units. 40 CFR 72.92(b)(1) (1993). Yet, this uncertainty and burden serve no real purpose if the allowance surrender requirements of §§ 72.91 and 72.92 are met. The allowance surrender procedures account for the emissions consequences of underutilization and consequent shifting of generation and therefore obviate the need for a reduced utilization plan under section 408(c)(1)(B) of the Act. Once underutilization is accounted for under §§ 72.91 and 72.92, there is no basis for requiring any further accounting through the designation of compensating units or energy conservation or unit efficiency measures.

The Agency concludes that § 72.43(e) should be revised so that the requirement to submit a reduced utilization plan for an underutilized Phase I unit is eliminated if the allowance surrender and reporting requirements of §§ 72.91 and 72.92 are met. This is a reasonable way of harmonizing sections 408(c)(1)(B) and 403(d) of the Act. The other criteria in § 72.43(e) are therefore superfluous and are removed. Sections 72.92(a)(2) and (3) and (b)(1) of the January 11, 1993 regulations, requiring submission of information in annual and other reports related to the removed criteria in § 72.43(e), are also unnecessary and are removed.[1]

III. Dispatch System

The dispatch system of a unit plays an important role in the allowance surrender calculations under §§ 72.91 and 72.92. For example, if a Phase I unit has a reduced utilization plan, the amount of reduced utilization accounted for under the plan (by a compensating unit, conservation or improved unit efficiency measures, or sulfur-free generators) must be determined. See 40 CFR 72.91(a)(3) (1993) (requiring calculation of "plan reductions"). The percentage change in the total sales of the dispatch system is a factor in calculating reduced utilization accounted for by a sulfur-free generator. 40 CFR 72.91(a)(3)(iii) (1993). As a further example, the total generation produced by the units and generators in a dispatch system during a Phase I calendar year must be used to determine the percentage of total dispatch system sales for the year that was generated by units and generators in the dispatch system. That percentage is used in calculating the emissions rate that is in turn used to determine how many allowances must be surrendered for the year. 40 CFR 72.92(c)(2)(v)(A) (1993).

The Agency is revising § 72.33(a), (b), and (c) to clarify certain matters concerning the determination of a unit's dispatch system. In addition, while § 72.33(f) allowed owners and operators of Phase I units to request that a Phase I unit be apportioned among its owners and their dispatch systems, certain revisions of the provision are needed to make it more workable and to coordinate it with the allowance surrender procedures under §§ 72.91 and 72.92.

A. Utility System and Identification of Dispatch System

Under § 72.33, each Phase I unit must be treated as part of a dispatch system for purposes of the allowance surrender procedures,[2] and the unit's utility

[1] In addition, § 72.91(a) of the January 11, 1993 regulations is revised to make it clear that the reporting requirements in § 72.91 apply only to calendar years in Phase I. Since § 72.92(a) applies to calendar years covered by § 72.91, this limitation applies to reporting under both sections. This reflects the fact that reduced utilization is a problem only in Phase I, when a minority of utility units are subject to Acid Rain SO_2 emissions limitations. See 56 FR 63018 and 58 FR 3605.

[2] Because the allowance surrender procedures are found in both § 72.91 and § 72.92, § 72.33(a) is revised to refer to both sections. The same change is made, for the same reason, in § 72.33(c)(4) and (e)(2) and § 72.33(f)(2)(iv) and (v). This conforms

Continued

system (as defined in § 72.2) is its dispatch system unless a complete identification of dispatch system including that unit is submitted under § 72.33.

In the January 11, 1993 regulations, utility system is defined as all interconnected units and generators controlled by the same utility operating company, as reported in the National Allowance Data Base (NADB). The difficulty with this definition is that the NADB was published in final form in March 1993 and necessarily reflects information on utility systems as of that time. The Agency recognizes that the owners and operators of some units have changed since 1993 and, particularly in light of increased competition in the electric utility industry, that more changes may occur during Phase I. In order to clarify that designated representatives may submit identifications of dispatch system to correct the utility system in which a unit or generator is listed in the NADB and that is used as its dispatch system, the Agency is revising the utility-system definition. Section 72.2 now defines utility system as all interconnected units and generators operated by the same utility company and does not refer to the NADB. Section 72.33(e)(1) is revised to state that unless otherwise provided in an identification of dispatch system, a unit or generator included in the NADB retains, as its dispatch system, the utility system reported in the NADB.

The NADB lists one utility operating company for each Phase I unit, Phase II unit, and non-affected unit in the database. Section 72.33(b)(2) of the January 11, 1993 regulations states that, except as provided under § 72.33(f), no Phase I unit may be listed in more than one identification of dispatch system. Although § 72.33(b) of the January 11, 1993 regulations does not state explicitly that other units or generators also must be confined to a single identification of dispatch system, other provisions of the regulations reflect such a limitation. For example, § 72.33(f) states that, except for the provisions for apportioning Phase I units under § 72.33(f), all provisions of the regulations "applicable to an affected source or affected unit * * * apply to the entire unit." 40 CFR 72.33(f)(6) (1993). By further example, the provisions requiring calculation of the "total" generation of the units and generators in a dispatch system are based on entire units and generators and do not provide for division of a unit's or generator's generation among more than one dispatch system, except for Phase I units apportioned under § 72.33(f). 40 CFR 72.92(c)(2)(v)(A) (1993). See also 40 CFR 72.91(a)(3)(iii)(A) (1993) ("actual annual" generation of the sulfur-free generator). In addition, dispatch system emissions rate, which is calculated using the actual annual emissions rate of all Phase II units in the dispatch system, is based on the utilization of entire units, and there is no provision allowing apportionment of Phase II units. 40 CFR 72.92(c)(2)(v)(C) (1993).

In order to remove any possible uncertainty concerning the treatment of Phase II units, non-affected units, and generators (including sulfur-free generators and, as discussed below, non-utility generators), the Agency is revising § 72.33(b)(2) to state that, with one exception, a unit or generator can be included in only one dispatch system.[3] The only exception is provided in § 72.33(f), under which a petition to apportion a Phase I unit among two or more dispatch systems may be submitted and approved. Section 72.33(f) provides that, if the petition is approved, the portions of the Phase I unit will be treated as separate units under §§ 72.91 and 72.92, the allowance surrender provisions.

Several other revisions are made here to the provisions concerning identification of dispatch system. While the January 11, 1993 regulations require a complete identification of dispatch system to include a list of all units and sulfur-free generators in the dispatch system, the revised rule expands that list to include all generators, including sulfur-free generators and non-utility generators. The January 11, 1993 regulations also require that if the submissions under §§ 72.91 and 72.92 by all designated representatives of the units in the identified dispatch system do not conform to the system-wide data provided for the dispatch system, the Administrator must reject the identification of dispatch system and all the submissions and require resubmission using the utility system of each unit as that unit's dispatch system. The revised regulations make such rejection optional so that the Agency may instead require corrections of the submissions and allow the identification of dispatch system to remain in effect. Sections 72.33(c)(4) and (e)(2) are revised to implement that change. Finally, § 72.33(b)(3) is revised so that the deadline for providing an identification of dispatch system is the same as for providing a petition to apportion a Phase I unit under § 72.33(f)(1), i.e., submission to EPA by January 30 of the year that the dispatch system is to take effect.

B. Apportionment of Phase I Units

The January 11, 1993 regulations only allow for the apportionment of Phase I units, and such apportionment is only for the purpose of applying the allowance surrender procedures of §§ 72.91 and 72.92. Under § 72.33(f) of the January 11, 1993 regulations, Phase I units with multiple owners may petition to divide up the unit, for allowance surrender, into portions, i.e., one or more individual owners' portions representing the owners' respective percentage ownership interests in the capacity of the unit and the remaining portion of the unit. The petition requests that each individual owner's portion be treated as part of a dispatch system different than the dispatch system of the remaining portion. If the petition is approved, the adjusted utilization (which, if greater than zero, is underutilization) is calculated for the entire unit for the Phase I year governed by the approved petition, and each portion of the unit takes its percentage of the adjusted utilization reflecting the ownership percentage that the portion of the unit represents. Each portion of the unit then uses its share of the entire unit's adjusted utilization in calculating how many allowances (if any) must be surrendered for underutilization of the Phase I units in its respective dispatch system.

The Agency received public comment expressing concern that requiring the portions of a Phase I unit to divide among them the adjusted utilization calculated for the entire unit fails to reflect differences among the Phase I unit owners' respective utilizations of their shares of the unit. While during the Phase I year one owner might take generation representing more than its percentage share of the baseline of the entire unit, another owner might take generation representing less than its percentage share.

Section 72.33(f) is revised to require the separate calculation of adjusted utilization under § 72.91 for each portion of the unit for which a petition to apportion is approved and for the remaining portion of the unit. This

these provisions with other provisions in the January 11, 1993 regulations that cite both sections.

[3] The units and generators included in a given dispatch system under § 72.33(b) or (e) may be changed under § 72.33(d). A complete identification of dispatch system, reflecting the change, must be submitted for both the dispatch system from which the units or generators are removed and the dispatch system to which the units or generators are added. If the entire dispatch system from which the units or generators are removed is included in the dispatch system to which they are added, then an identification of dispatch system is necessary only for the latter dispatch system.

approach meets the commenters' concerns. The separate calculation of adjusted utilization is made a uniform requirement for all apportioned Phase I units in order to ensure that overall there is no net adverse environmental impact from apportionment and to avoid the potential confusion and administrative burden of having two entirely different approaches for calculating reduced utilization of apportioned units.

Public comment has also been directed at the requirement that apportionment be based exclusively on the owners' percentage ownership interest in the capacity of the Phase I unit. According to commenters, unit owners in some cases have entered into private agreements to divide up the allowances allocated to the unit based on percentage ownership of capacity during 1985–1987 while owners in other cases have agreed to divide up allocated allowances based on each owner's percentage share of utilization of the unit during 1985–1987. Commenters have requested that the regulations allow the basis for unit apportionment for purposes of allowance surrender to be consistent with the basis for dividing up the unit's allowance allocation.

The Agency is willing to meet these concerns and accommodate underlying private agreements among unit owners so long as the resulting regulatory provisions are not too complex and do not appear to cause overall any net adverse environmental impact. This is consistent with the Agency's general approach of avoiding interfering with existing relationships among owners and operators. See 58 FR 3598. Consequently, the revised § 72.33(f) allows the designated representative to elect in the apportionment petition one of two methods for apportioning the Phase I unit: the first method is based on the average of the owner's percentage ownership of the capacity of the unit for each year in 1985–1987; and the second method is based on the average of the unit's annual utilization that is attributed to the owner for 1985–1987. In order to avoid gaming by changing the apportionment method to minimize allowance surrender each year, the regulations make the selection of the apportionment method a one-time election for each Phase I unit. The same apportionment method must be used for all portions of the units for all years in Phase I for which any petition to apportion is approved and in effect.

Further, the Agency is concerned that, whichever apportionment method is elected, the baselines and actual utilizations for the portions of the unit must not double-count or undercount any of the baseline and actual utilization for the entire unit. Consequently, the revised regulations require that the sum of the baselines of the portions of the unit (including the individual owners' portions and the remaining portion of the unit) equal 100% of the baseline of the entire unit. Similarly, for each Phase I year, the sum of the actual utilizations of the portions must equal 100% of the entire unit's actual utilization. In order to ensure that the attribution of a unit's utilization (whether baseline or actual utilization) to specific owners is not arbitrary, the regulations require that the same accounting procedures used to attribute the unit's fuel costs among the owners be used for attributing utilization. This is reasonable because fuel costs at a unit are directly related to the unit's utilization (i.e., the mmBtu of fuel consumed).

The revised § 72.33(f) establishes the requirements for the contents of a complete petition to apportion and provides that the Administrator may prescribe a format. In addition to the requirements in the January 11, 1993 regulations, the petition must include the election of apportionment method and a list of the units and generators and apportioned units to be included in the dispatch system proposed for each portion of the unit covered by the petition. The designated representative is not required to submit with the petition the documentation supporting the baselines for the portions of the unit or the dispatch systems proposed for each portion of the unit. The Agency maintains that this is a sound approach in light of: the certifications by the designated representatives that the information in the petition is true, accurate, and complete; the Agency's ability to require submission of additional information before acting on the petition or at any other time; and the potential for after-the-fact spot audits.

The January 11, 1993 regulations require that, with regard to the dispatch system proposed for each owner's portion of the unit, the dispatch system must be a group of all units and generators that are interconnected and centrally dispatched and that are included in the same utility system, holding company, or power pool. The difficulty with this requirement is that a Phase I unit to be apportioned has multiple owners and only one owner may be the operator. A non-operating owner's portion of the unit cannot be in the "utility system" of the non-operating owner's other units and generators because, as defined in § 72.2, only units and generators with the same operator comprise a "utility system". In order to avoid this problem, the revised regulations require that the proposed dispatch system for each owner's portion of the unit include all units and generators that are interconnected and centrally dispatched by a single utility system, the service company of a single holding company, or a single power pool.

Upon approval of an apportionment petition and the proposed dispatch systems, the allowance surrender formulas are applied to each portion of the Phase I unit and its respective dispatch system. The designated representative of the apportioned unit must surrender all allowances required for surrender by each portion of the unit.

There is no provision in the January 11, 1993 regulations for termination of an approved apportionment of a Phase I unit. The Agency is concerned that after approval of an apportioned Phase I unit, circumstances may change so that the apportionment is no longer appropriate. For example, the owner of one portion of the apportioned unit could sell its entire interest in the unit and stop dispatching that portion of the unit. The dispatch system that, because of the approved apportionment, includes that portion of the unit would now include a portion of the unit that was no longer centrally dispatched along with the other units and generators in the dispatch system. That aspect of the approved apportionment (and the designated representative's certification concerning the continued central dispatching of the dispatch system) would no longer be accurate and the apportionment should be terminated. Of course, a new apportionment reflecting the new composition of ownership interests in the Phase I unit could be submitted for approval. Even without any change in ownership or dispatching, the owners of the Phase I unit might determine that an apportionment is no longer desirable. To accommodate changes in circumstance and to provide owners more flexibility, the revised regulations include a procedure for terminating apportionments. If a notice of termination is signed by the designated representatives of all units that could be affected by the termination (i.e., of all units included in all dispatch systems that include any portion of the unit) and submitted by January 30, the apportionment is terminated for that year and all remaining Phase I years.

IV. Emissions Rate

The January 11, 1993 regulations require that the emissions consequences of underutilization for a dispatch system be estimated for each Phase I year by multiplying that underutilization (referred to as "dispatch system adjusted utilization") by an emissions rate for generation used by the dispatch system to compensate for the underutilization. The emissions rate is composed of an emissions rate for compensating generation produced by non-Phase I units and generators within the dispatch system and another emissions rate for compensating generation produced outside the dispatch system by non-Phase I, non-foreign units and generators and acquired by the dispatch system. To calculate the composite emissions rate, the emissions rate for generation within the dispatch system is weighted by a fraction equal to total generation by the units and generators in the dispatch system divided by total dispatch system sales (i.e., total sales for direct use or resale) of the named utility system, holding company, or power pool that is the dispatch system) for the year. The actual annual emissions rates of the Phase II units in the dispatch system are used as a proxy for the actual emissions rates of all non-Phase I units and generators in the dispatch system. Similarly, the emissions rate for generation outside the dispatch system is weighted by the fraction of total dispatch system sales that is accounted for by generation outside the dispatch system. NERC region emissions rates for non-Phase I, non-foreign units for 1985 are used as a proxy for the current emissions rates of non-Phase I, non-foreign units and generators.

In light of public comment concerning compensating generation from non-utility generators, the calculation of the emissions rate of non-Phase I units in the dispatch system, and 1985 NERC emissions rates, the Agency is revising these aspects of the January 11, 1993 regulations.

A. Non-Utility Generators

The Agency received public comment that some utilities are required by Federal or State law or by order of their State public utility commission to purchase electricity from non-utility generators. This required purchase of electricity may result in reduced utilization of the utility's own Phase I units. Since non-utility generators may have a different—apparently often lower—emissions rate than that of the utility's Phase II units or the NERC region emissions rate, the commenters urged that the formulas in § 72.92 be revised to take account of this third possible source of compensating generation.

The allowance surrender procedures in §§ 72.91 and 72.92 are not intended to result in a precise calculation of the emissions consequences of underutilization of Phase I units. The procedures were adopted to provide an administratively feasible method of developing reasonable estimates of the emissions resulting from generation compensating for underutilization. In light of this goal, the January 11, 1993 regulations establish a composite emissions rate based on two general categories of compensating generation. Because some utilities are obligated by law to purchase non-utility generation that may force them to reduce generation at their own units and because non-utility generators tend to have relatively low SO_2 emissions, the Agency is revising the regulations to take account of non-utility generation. This change increases somewhat the complexity of the allowance surrender formulas but, as a practical matter, only utilities that must buy from non-utility generators are affected by the change. While the Agency maintains that, on balance, the change is reasonable, the Agency stresses that the allowance surrender formulas are only intended to estimate emissions and that any more refinements that would further complicate the formulas would seem to be counterproductive.

The provisions incorporating non-utility generators into the allowance surrender procedures are premised on the fact that utilities acquiring non-utility generation have very limited information about the non-utility generators. Utilities contract to purchase non-utility generation but, as a result of not owning or operating these generators, have little or no knowledge about the fuels used by, and the heat rates and emission rates of, the generators. The Agency similarly has limited information about non-utility generators because they are not affected units. Consequently, the revised regulations use the available information on these generators (i.e., their emissions limitations and Kwh sales to utilities) to estimate emissions from compensating generation acquired from them.

In order to be treated as a non-utility generator, a power production facility cannot be an affected unit or a sulfur-free generator. The facility must use its most stringent federally enforceable or State enforceable SO_2 emissions limitation for the Phase I year as the estimate of its actual emissions rate.[4] With one exception, if no unit-specific limitation that can be expressed in lbs/mmBtu is applicable to the facility for the year, then the facility cannot be treated as a non-utility generator for that year. The only exception is where a facility without an emissions limitation is authorized by law to use only natural gas as fuel; in that case the most stringent emissions limitation for the facility is deemed to be 0.0006 lbs/mmBtu.[5]

As discussed above, the January 11, 1993 regulations calculate a composite emissions rate for a dispatch system reflecting compensating generation from within or from outside the dispatch system. The revised regulations introduce a third category, non-utility generation from non-utility generators, which equals the total generation acquired from non-utility generators that the dispatch system is required to purchase by Federal or State law or order of a utility regulatory commission or under a contract awarded as the result of a power purchase solicitation required by Federal or State law or utility regulatory commission order. To prevent double-counting, such generation is excluded in calculating the fractions of dispatch system sales accounted for by generation within or outside the dispatch system. Total non-utility generation from non-utility generators is used to calculate the fraction of dispatch system sales accounted for by such generators.

The non-utility generator average emissions rate is calculated using the most stringent emissions limitation (or for natural-gas-only facilities, the default emissions rate) for each non-utility generator from which the dispatch system was required to purchase electricity, weighted by the amount (kwh) of required electricity purchases during the year. The fraction of generation from non-utility generators and the non-utility generator average emissions rate are used, along with the comparable data for generation within and outside the dispatch system, to derive the composite emissions rate multiplied by the underutilization for the dispatch system for the year.[6] This yields the total number of allowances

[4] If emissions limitations vary depending on the fuel used, the most stringent emissions limitation must be calculated for each fuel used. The resulting limitation with the highest lbs/mmBtu must be used as the estimate for the actual emissions rate of the non-utility generator.

[5] This default emissions rate is the average SO_2 emissions rate for natural gas and was used for purposes of allocating allowances to utility units under section 405 of the Act. See Compilation of Air Pollutant Emission Factors (AP-42), Vol. 1 at 1.4-1 through 1.4-3, US EPA (4th ed. 1985).

[6] The dispatch-system-wide data related to non-utility generators must be included in the dispatch system data report under § 72.92(b).

that must be surrendered by Phase I units in the dispatch system.

B. Dispatch System Emissions Rate

The January 11, 1993 regulations use the actual annual emissions rate for a dispatch system's Phase II units to estimate the emissions rate for the dispatch system's non-Phase I units. In the December 3, 1991 proposed regulations, the Agency proposed to weight the actual annual emissions rate for each Phase II unit by the amount of the Phase II unit's increase in utilization for the year over baseline. 56 FR 63147–48 (Dec. 3, 1991). The January 11, 1993 regulations adopted a simpler approach of weighting actual annual emissions rates by each Phase II unit's total utilization for the year. 58 FR 3685.

However, the Agency has received public comments suggesting that weighting by the increase over baseline provides a more realistic estimate. It seems reasonable to treat a utilization reduction since 1985–1987 of one unit in a dispatch system as being compensated for by a utilization increase since 1985–1987 of another unit in that dispatch system. Further, this approach is similar to that taken with regard to sulfur-free generators. Compensating generation claimed to be acquired from sulfur-free generators under a reduced utilization plan cannot exceed the amount of electricity produced by the sulfur-free generator in excess of the average annual amount produced by the generator in 1985–1987. See 58 FR 3682. For these reasons, the Agency is revising the provisions for calculating dispatch system emissions rate to weight Phase II units' actual emissions rates by each unit's increased utilization over baseline. However, the Agency recognizes that it is possible that no Phase II unit in a dispatch system has increased utilization over baseline. In that case, non-affected units are providing the compensating generation but, because of the lack of emissions data from such units, the Phase II unit emissions rate must still be used as a proxy for non-affected units' emissions rates. The revised regulations therefore provide that if no Phase II unit is used above baseline, an average rate must be calculated using the Phase II units' annual actual emissions rates weighted by each unit's total utilization. Moreover, if a dispatch system has no Phase II unit emissions rate for the year, the NERC region emissions data will be used instead.

C. NERC Region Emissions Rate

The January 11, 1993 regulations use 1985 NERC data to establish the non-Phase I, non-foreign emissions rate for each NERC region. The 1985 emissions rate for units in the NERC region is multiplied by the fraction of non-Phase I, nonforeign units in the NERC region in order to exclude generation and resulting emissions from Phase I units and all foreign units and generators.

The Agency has learned through public comment that the figures in the regulations for the fraction of non-Phase I, non-foreign generation contained inadvertent errors and failed to actually exclude foreign generation. The Agency has recalculated the fractions of non-Phase I, non-foreign generation for each NERC region. Table 1 of the revised regulations includes the corrected figures so that foreign generation is excluded as intended.[7]

VI. Administrative Requirements

A. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (Oct. 4, 1993), the Administrator must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a "significant regulatory action" because the rule seems to raise novel legal or policy issues. As such, this action was submitted to OMB for review. Any written comments from OMB to EPA, any written EPA response to those comments, and any changes made in response to OMB suggestions or recommendations are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** section of this preamble.

B. Unfunded Mandates Act

Section 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act") (signed into law on March 22, 1995) requires that the Agency prepare a budgetary impact statement before promulgating a rule that includes a Federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of $100 million or more in any one year. Section 203 requires the Agency to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely affected by the rule.

Under section 205 of the Unfunded Mandates Act, the Agency must identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the Agency explains why this alternative is not selected or the selection of this alternative is inconsistent with law.

Because this direct final rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than $100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments. However, as discussed in this preamble, the rule has the net effect of reducing the burden of part 72 of the Acid Rain regulations on regulated entities, including both investor-owned and municipal utilities.

C. Paperwork Reduction Act

The information collection requirements in this rule have been approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, and have been assigned control number 2060–0258.

[7] The definition of "sulfur-free generation" is revised to make it clear that only facilities in the 48 contiguous states in the United States or the District of Columbia may qualify as sulfur-free generators under reduced utilization plans. All foreign generation (including foreign generation that involves no SO_2 emissions) that offset underutilization is already excluded from allowance surrender in the revised Table 1. Allowing foreign facilities to be designated as sulfur-free generators and the generation acquired from them to be used to offset underutilization would double-count such generation.

This collection of information reduces the estimated burden, as compared to the burden under the January 11, 1993 regulations, by an average of 35 hours per response for about 110 responses. These estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. An Information Collection Request document and estimates of the public reporting burden were prepared in connection with the January 11, 1993 regulations. 56 FR 63098; 58 FR 3650.

Send comments regarding this burden analysis or any other aspect of this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, EPA, 401 M Street, SW. (Mail Code 2136), Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, requires each federal agency to consider potential impacts of its regulations on small business "entities." Under 5 U.S.C. 604(a), an agency issuing a notice of proposed rulemaking must prepare and make available for public comment a regulatory flexibility analysis. Such an analysis is not required if the head of an agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, pursuant to 5 U.S.C. 605(b).

In the preamble of the January 11, 1993 regulations, the Administrator certified that these regulations, including the provisions revised by today's final rule, would not have a significant impact. 58 FR 3649. The final rule revisions adopted today are not significant enough to change the economic impact addressed in the January 11, 1993 preamble. Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the revised rule will not have a significant, adverse impact on a substantial number of small entities.

E. Miscellaneous

In accordance with section 117 of the Act, issuance of this rule was preceded by consultation with any appropriate advisory committees, independent experts, and federal departments and agencies.

List of Subjects in 40 CFR Part 72

Environmental protection, Acid rain program, Air pollution control, Compliance plans, Electric utilities, Permits, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: March 31, 1995.

Carol M. Browner,

Administrator, U.S. Environmental Protection Agency.

For the reasons set forth in the preamble, chapter I of title 40 of the Code of Federal Regulations is amended as follows.

PART 72—[AMENDED]

1. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 72.2 is amended by revising the definitions for "sulfur-free generation" and "utility system" to read as follows:

§ 72.2 Definitions.

* * * * *

Sulfur-free generation means the generation of electricity by a process that does not have any emissions of sulfur dioxide, including hydroelectric, nuclear, solar, or wind generation. A "sulfur-free generator" is a generator that is located in one of the 48 contiguous States or the District of Columbia and produces "sulfur-free generation."

* * * * *

Utility system means all interconnected units and generators operated by the same utility operating company.

* * * * *

3. Section 72.33 is amended by revising paragraphs (a), (b)(2), (b)(3), (c)(2), (c)(4), (e), and (f) to read as follows:

§ 72.33 Identification of dispatch system.

(a) Every Phase I unit shall be treated as part of a dispatch system for purposes of §§ 72.91 and 72.92 in accordance with this section.

(b) * * *

(2) Except as provided in paragraph (f) of this section, each unit or generator may be included in only one dispatch system.

(3) Any identification of dispatch system must be submitted by January 30 of the first year for which the identification is to be in effect.

(c) * * *

(2) The list of all units and generators (including sulfur-free generators) in the dispatch system.

* * * * *

(4) The following statement: "I certify that, except as otherwise required under a petition as approved under 40 CFR 72.33(f), the units and generators listed herein are and will continue to be interconnected and centrally dispatched, and will be treated as a dispatch system under 40 CFR 72.91 and 72.92, during the period that this identification of dispatch system is in effect. During such period, all information concerning these units and generators and contained in any submissions under 40 CFR 72.91 and 72.92 by me and the other designated representatives of these units shall be consistent and shall conform with the data in the dispatch system data reports under 40 CFR 72.92(b). I am aware of, and will comply with, the requirements imposed under 40 CFR 72.33(e)(2)."

* * * * *

(e) (1) Any unit or generator not listed in a complete identification of dispatch system that is in effect shall treat its utility system as its dispatch system and, if such unit or generator is listed in the NADB, shall treat the utility system reported under the data field "UTILNAME" of the NADB as its utility system.

(2) During the period that the identification of dispatch system is in effect all information that concerns the units and generators in a given dispatch system and that is contained in any submissions under §§ 72.91 and 72.92 by designated representative of these units shall be consistent and shall conform with the data in the dispatch system data reports under § 72.92(b). If this requirement is not met, the Administrator may reject all such submissions and require the designated representatives to make the submissions under §§ 72.91 and 72.92 (including the dispatch system data report) treating the utility system of each unit or generator as its respective dispatch system and treating the identification of dispatch system as no longer in effect.

(f)(1) Notwithstanding paragraph (e)(1) of this section or any submission of an identification of dispatch system under paragraphs (b) or (d) of this section, the designated representative of a Phase I unit with two or more owners may petition the Administrator to treat, as the dispatch system for an owner's portion of the unit, the dispatch system of another unit.

(i) The owner's portion of the unit shall be based on one of the following apportionment methods:

(A) *Owner's share of the unit's capacity in 1985–1987.* Under this method, the baseline of the owner's portion of the unit shall equal the baseline of the unit multiplied by the average of the owner's percentage ownership of the capacity of the unit for each year during 1985–1987. The actual utilization of the owner's portion of the unit for a year in Phase I shall equal the actual utilization of the unit for the year that is attributed to the owner.

(B) *Owner's share of the unit's baseline.* Under this method, the baseline of the owner's portion of the unit shall equal the average of the unit's annual utilization in 1985–1987 that is attributed to the owner. The actual utilization of the owner's portion of the unit for a year in Phase I shall equal the actual utilization of the unit for the year that is attributed to the owner.

(ii) The annual or actual utilization of a unit shall be attributed, under paragraph (f)(1)(i) of this section, to an owner of the unit using accounting procedures consistent with those used to determine the owner's share of the fuel costs in the operation of the unit during the period for which the annual or actual utilization is being attributed.

(iii) Upon submission of the petition, the designated representative may not change the election of the apportionment method or the baseline of the owner's portion of the unit.

The same apportionment method must be used for all portions of the unit for all years in Phase I for which any petition under paragraph (f)(1) of this section is approved and in effect.

(2) The petition under paragraph (f)(1) of this section shall be submitted by January 30 of the first year for which the dispatch system proposed in the petition will take effect, if approved. A complete petition shall include the following elements in a format prescribed by the Administrator:

(i) The election of the apportionment method under paragraph (f)(1)(i) of this section.

(ii) The baseline of the owner's portion of the unit and the baseline of any other owner's portion of the unit for which a petition under paragraph (f)(1) of this section has been approved or has been submitted (and not disapproved) and a demonstration that the sum of such baselines and the baseline of any remaining portion of the unit equals 100 percent of the baseline of the unit. The designated representative shall also submit, upon request, either:

(A) Where the unit is to be apportioned under paragraph (f)(1)(i)(A) of this section, documentation of the average of the owner's percentage ownership of the capacity of the unit for each year during 1985–1987; or

(B) Where the unit is to be apportioned under paragraph (f)(1)(i)(B) of this section, documentation showing the attribution of the unit's utilization in 1985, 1986, and 1987 among the portions of the unit and the calculation of the annual average utilization for 1985–1987 for the portions of the unit.

(iii) The name of the proposed dispatch system and a list of all units (including portions of units) and generators in that proposed dispatch system and, upon request, documentation demonstrating that the owner's portion of the unit, along with the other units in the proposed dispatch system, are a group of all units and generators that are interconnected and centrally dispatched by a single utility company, the service company of a single holding company, or a single power pool.

(iv) The following statement, signed by the designated representatives of all units in the proposed dispatch system: "I certify that the units and generators in the dispatch system proposed in this petition are and will continue to be interconnected and centrally dispatched, and will be treated as a dispatch system under 40 CFR 72.91 and 72.92, during the period that this petition, as approved, is in effect."

(v) The following statement, signed by the designated representatives of all units in all dispatch systems that will include any portion of the unit if the petition is approved: "During the period that this petition, if approved, is in effect, all information that concerns the units and generators in any dispatch system including any portion of the unit apportioned under the petition and that is contained in any submissions under 40 CFR 72.91 and 72.92 by me and the other designated representatives of these units shall be consistent and shall conform to the data in the dispatch system data reports under 40 CFR 72.92(b). I am aware of, and will comply with, the requirements imposed under 40 CFR 72.33(f) (4) and (5)."

(3) (i) The Administrator will approve in whole, in part, or with changes or conditions, or deny the petition under paragraph (f)(1) of this section within 90 days of receipt of the petition. The Administrator will treat the petition, as changed or conditioned upon approval, as amending any identification of dispatch system that is submitted prior to the approval and includes any portion of the unit for which the petition is approved. Where any portion of a unit is not covered by an approved petition, that remaining portion of the unit shall continue to be part of the unit's dispatch system.

(ii) In approving the petition, the Administrator will determine, on a case-by-case basis, the proper calculation and treatment, for purposes of the reports required under §§ 72.91 and 72.92, of plan reductions and compensating generation provided to other units.

(4) The designated representative for the unit for which a petition is approved under paragraph (f)(3) of this section and the designated representatives of all other units included in all dispatch systems that include any portion of the unit shall submit all annual compliance certification reports, dispatch system data reports, and other reports required under §§ 72.91 and 72.92 treating, as a separate Phase I unit, each portion of the unit for which a petition is approved under paragraph (f)(3) of this section and the remaining portion of the unit. The reports shall include all required calculations and demonstrations, treating each such portion of the unit as a separate Phase I unit. Upon request, the designated representatives shall demonstrate that the data in all the reports under §§ 72.91 and 72.92 has been properly attributed or apportioned among the portions of the unit and the dispatch systems and that there is no undercounting or double-counting with regard to such data.

(i) The baseline of each portion of the unit for which a petition is approved shall be determined under paragraphs (f)(1) (i) and (ii) of this section. The baseline of the remaining portion of such unit shall equal the baseline of the unit less the sum of the baselines of any portions of the unit for which a petition is approved.

(ii) The actual utilization of each portion of the unit for which a petition is approved shall be determined under paragraphs (f)(1) (i) and (ii) of this section. The actual utilization of the remaining portion of such unit shall equal the actual utilization of the unit less the sum of the actual utilizations of any portions of the unit for which a petition is approved. Upon request, the designated representative of the unit shall demonstrate in the annual compliance certification report that the requirements concerning calculation of actual utilization under paragraph (f)(1)(ii) and any requirements established under paragraph (f)(3) of this section are met.

(iii) Except as provided in paragraph (f)(5) of this section, the designated representative shall surrender for deduction the number of allowances calculated using the formula in § 72.92(c) and treating, as a separate Phase I unit, each portion of unit for which a petition is approved under paragraph (f)(3) of this section and the remaining portion of the unit.

(5) In the event that the designated representatives fail to make all the proper attributions, apportionments,

calculations, and demonstrations under paragraph (f)(4) of this section and §§ 72.91 and 72.92, the Administrator may require that:

(i) All portions of the unit be treated as part of the dispatch system of the unit in accordance with paragraph (e)(1) of this paragraph and any identification of dispatch system submitted under paragraph (b) or (d) of this section;

(ii) The designated representatives make all submissions under §§ 72.91 and 72.92 (including the dispatch system data report), treating the entire unit as a single Phase I unit, in accordance with paragraph (e)(1) of this paragraph and any identification of dispatch system submitted under paragraph (b) or (d) of this section; and

(iii) The designated representative surrender for deduction the number of allowances calculated, consistent with the reports under paragraph (f)(5)(ii) of this section and §§ 72.91 and 72.92, using the formula in § 72.92(c) and treating the entire unit as a single Phase I unit.

(6) The designated representative may submit a notification to terminate an approved petition by January 30 of the first year for which the termination is to take effect. The notification must be signed and certified by the designated representatives of all units included in all dispatch systems that include any portion of the unit apportioned under the petition. Upon receipt of the notification meeting the requirements of the prior two sentences by the Administrator, the approved petition is no longer in effect for that year and the remaining years in Phase I and the designated representatives shall make all submissions under §§ 72.91 and 72.92 treating the petition as no longer in effect for all such years.

(7) Except as expressly provided in paragraphs (f)(1) through (6) of this section or the Administrator's approval of the petition, all provisions of the Acid Rain Program applicable to an affected source or an affected unit shall apply to the entire unit regardless of whether a petition has been submitted or approved, or reports have been submitted, under such paragraphs. Approval of a petition under such paragraphs shall not constitute a determination of the percentage ownership in a unit under any other provision of the Acid Rain Program and shall not change the liability of the owners and operators of an affected unit that has excess emissions under § 72.9(e).

4. Section 72.43 is amended by revising paragraph (e) to read as follows:

§ 72.43 Phase I reduced utilization plans.

* * * * *

(e) *Failure to Submit a Plan.* The designated representative of a Phase I unit will be deemed not to violate, during a Phase I calendar year, the requirement to submit a reduced utilization plan under paragraph (b)(1) or (4) of this section if the designated representative complies with the allowance surrender and other requirements of §§ 72.33, 72.91, and 72.92 of this chapter.

* * * * *

5. Section 72.91 is amended by revising the introductory language of paragraph (a) (the formula is unchanged) to read as follows:

§ 72.91 Phase I unit adjusted utilization.

(a) *Annual Compliance Certification Report.* The designated representative for each Phase I unit shall include in the annual compliance certification report the unit's adjusted utilization for the calendar year in Phase I covered by the report, calculated as follows:

* * * * *

6. Section 72.92 is amended by revising paragraphs (a), (b)(2)(ii)(F), (b)(2)(ii)(G), (b)(2)(ii)(H), (c)(2)(v) and Table 1, removing and reserving paragraph (b)(1), and adding paragraphs (b)(2)(ii)(I) and (b)(2)(ii)(J) to read as follows:

§ 72.92 Phase I unit allowance surrender.

(a) *Annual Compliance Certification Report.* If a Phase I unit's adjusted utilization for the calendar year in Phase I under § 72.91(a) is greater than zero, then the designated representative shall include in the annual compliance certification report the number of allowances that shall be surrendered for adjusted utilization using the formula in paragraph (c) of this section and the calculations that were performed to obtain that number.

(b) *Other Submissions.*

(1) [Reserved]

(2) * * *

(ii) * * *

(F) The calculation of "dispatch system emissions rate" under paragraph (c)(2)(v)(B) of this section;

(G) The calculation of "fraction of generation from non-utility generators" under paragraph (c)(2)(v)(C) of this section;

(H) The calculation of "non-utility generator average emissions rate" under paragraph (c)(2)(v)(F) of this section;

(I) A certification that each designated representative will use these figures, as appropriate, in its annual compliance certification report and will submit upon request the data supporting these calculations; and

(J) The signatures of all the designated representatives.

(c) * * *

(2) * * *

(v) *Calculating Emissions Rate.* "Emissions rate" (in lbs/mmBtu) is the weighted average emissions rate for sulfur dioxide of all units and generators, within and outside the dispatch system, that contributed to the dispatch system's electrical output for the year, calculated as follows:

Emissions rate = [fraction of generation within dispatch system × dispatch system emissions rate] + [fraction of generation from non-utility generators × non-utility generator average emissions rate] + [fraction of generation outside dispatch system × fraction of non-Phase 1 and non-foreign generation in NERC region × NERC region emissions rate]

Where:

(A) "Fraction of generation within dispatch system" is the fraction of the dispatch system's total sales accounted for by generation from units and generators within the dispatch system, other than generation from non-utility generators. This term equals the total generation (in Kwh) by all units and generators within the dispatch system for the calendar year minus the total non-utility generation from non-utility generators within the dispatch system for the calendar year and divided by the total sales (in Kwh) by the dispatch system for the calendar year.

(B) Dispatch system emissions rate" is the weighted average rate (in lbs/mmBtu) for the dispatch system calculated as follows:

Dispatch system emissions rate =

$$\sum_{i=1}^{k} g_i r_i \div \sum_{i=1}^{k} g_i$$

Where:

g_i = the difference between a Phase II unit's actual utilization for the calendar year and that Phase II unit's baseline. If that difference is less than or equal to zero, then the difference shall be treated as zero only for purposes of paragraph (c)(2)(v) of this section and that unit will be excluded from the calculation of dispatch system emissions rate. Notwithstanding the prior sentence, if the actual utilization of each Phase II unit for the year is equal to or less than the baseline, then g_i shall equal a Phase II unit's actual utilization for the year. Notwithstanding any provision in this paragraph (c)(2)(v)(B) to the contrary, if the actual utilization of each Phase II unit in the dispatch system is zero or there are no Phase II units in the dispatch system, then the dispatch system emissions rate shall equal the fraction of non-Phase I and non-foreign generation in the NERC region multiplied by the NERC region emissions rate.

r_i = a Phase II unit's emissions rate (in lbs/mmBtu), determined in accordance with part 75 of this chapter, for the calendar year.

k = number of Phase II units in the dispatch system.

(C) "Fraction of generation from non-utility generators" is the fraction of the dispatch system's total sales accounted for by generation acquired from non-utility generators within or outside the dispatch system. This term equals the total non-utility generation from non-utility generators (within or outside the dispatch system) for the calendar year divided by the total sales (in Kwh) by the dispatch system for the calendar year.

(D) "Non-utility generator" is a power production facility (within or outside the dispatch system) that is not an affected unit or a sulfur-free generator and that has a "non-utility generator emissions rate" for the calendar year under paragraph (c)(2)(v)(F) of this section.

(E) "Non-utility generation" is the generation (in Kwh) that the dispatch system acquired from a non-utility generator during the calendar year as required by federal or State law or an order of a utility regulatory authority or under a contract awarded as the result of a power purchase solicitation required by federal or State law or an order of a utility regulatory authority.

(F) "Non-utility generator average emissions rate" is the weighted average rate (in lbs/mmBtu) for the non-utility generators calculated as follows:

Non-utility generator average emissions rate =

$$\sum_{i=1}^{n} N_i R_i \div \sum_{i=1}^{n} N_i$$

Where:

N_i = non-utility generation from a non-utility generator;

R_i = non-utility generator emissions rate for the calendar year for a non-utility generator, which shall equal the most stringent federally enforceable or State enforceable SO_2 emissions limitation applicable for the calendar year to such power production facility, as determined in accordance with paragraphs (c)(2)(v)(F) (*1*), (*2*), and (*3*) of this section; and

n = number of non-utility generators from which the dispatch system acquired non-utility generation. If n equals zero, then the non-utility generator average emissions rate shall be treated as zero only for purposes of paragraph (c)(2)(v) of this section.

(*1*) For purposes of determining the most stringent emissions limitation, applicable emissions limitations shall be converted to lbs/mmBtu in accordance with Appendix B of this part. If an applicable emissions limitation cannot be converted to a unit-specific limitation in lbs/mmBtu under appendix B of this part, then the limitation shall not be used in determining the most stringent emissions limitation. Where the power production facility is subject to different emissions limitations depending on the type of fuel it uses during the calendar year, the most stringent emissions limitation shall be determined separately with regard to each type of fuel and the resulting limitation with the highest amount of lbs/mmBtu shall be treated as the facility's most stringent federally enforceable or State enforceable emissions limitation.

(*2*) If there is no applicable emissions limitation that can be used in determining the most stringent emissions limitation under paragraph (c)(2)(v)(F)(*1*) of this section, then the power production facility has no non-utility generator emissions rate for purposes of paragraphs (c)(2)(v) (D) and (F) of this section and the generation from the facility shall be treated, for purposes of this paragraph (c)(2)(v) as generation from units and generators within the dispatch system if the facility is within the dispatch system or as generation from units and generators outside the dispatch system if the facility is outside the dispatch system.

(*3*) Notwithstanding paragraphs (c)(2)(v)(F) (*1*) and (*2*) of this section, if the power production facility is authorized under federal or State law to use only natural gas as fuel, then the most stringent emissions limitation for the facility for the calendar year shall be deemed to be 0.0006 lbs/mmBtu.

(G) "Fraction of generation outside dispatch system" = 1 − fraction of generation within dispatch system − fraction of generation from non-utility generators.

(H) "Fraction of non-Phase I and non-foreign generation in NERC region" is the portion of the NERC region's total sales generated by units and generators other than Phase I units or foreign sources in the unit's NERC region in 1985, as set forth in Table 1 of this section.

(I) "NERC region emissions rate" is the weighted average emission rate (in lbs/mmBtu) for the unit's NERC region in 1985, as set forth in Table 1 of this section.

TABLE 1.—NERC REGION GENERATION AND EMISSIONS RATE IN 1985

NERC region	Fraction of non-phase I and non-foreign generation in NERC region	NERC weighted average emissions rate (lbs/mmBtu)
WSCC	0.847	0.466
SPP	0.948	0.647
SERC	0.749	1.315
NPCC	0.423	1.058
MAPP	0.725	1.171
MAIN	0.682	1.495
MAAC	0.750	1.599
ERCOT	1.000	0.491
ECAR	0.549	1.564

[FR Doc. 95-8601 Filed 4-10-95; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 72

[FRL-5186-4]

RIN 2060-AE59

Acid Rain Program: Permits

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Title IV of the Clean Air Act (the Act), as amended by the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The program sets emissions limitations to reduce acidic deposition and its serious, adverse effects on natural resources, ecosystems, materials, visibility, and public health. On January 11, 1993, the Agency promulgated final rules under title IV. Several parties filed petitions for review of the rules. On January 10, 1995, EPA and the parties signed a settlement agreement addressing reduced utilization issues.

Based on a review of the record, the Agency concludes that the January 11, 1993, regulations concerning reduced utilization should be revised. The regulations require that, unless certain requirements are met, the designated representative of a unit in Phase I of the program whose annual utilization of fuel is less than the unit's average annual utilization in 1985–1987 submit reduced utilization plans. The regulations also require designated representatives to submit end-of-year compliance certification reports that, based on specified formulas, estimate the sulfur dioxide emissions resulting from underutilization of Phase I units and to surrender allowances for the estimated emissions. The Agency is revising the regulations to simplify the criteria for determining whether a reduced utilization plan must be submitted: where the end-of-year reporting and allowance surrender requirements are met, such plans are not required. Further, the Agency is revising the formulas for estimating the emissions resulting from underutilization to correct certain errors, clarify certain provisions, and take account of and facilitate compliance by Phase I units that have multiple owners or whose owners are required by law to purchase electricity from non-utility power production facilities.

Because the rule revision is consistent with the January 10, 1995, settlement and the Agency does not anticipate receiving adverse comments, the revision is also being issued as a direct final rule in the final rules section of this **Federal Register**.

DATES: Comments on the regulations proposed by this action must be received on or before May 11, 1995.

ADDRESSES: *Comments*. All written comments must be identified with the appropriate docket number and must be submitted in duplicate to: EPA Air Docket Section (LE-131), Waterside Mall, Room 1500, 1st floor, 401 M St. SW., Washington, DC 20460.

Docket. Docket No. A-93-40, containing supporting information used to develop the proposal, copies of all comments received, and responses to comments, is available for public inspection and copying from 8:30 a.m. to 12:00 p.m. and 1:00 p.m. to 3:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section, Waterside Mall, Room 1500, 1st floor, 401 M St. SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Dwight C. Alpern, Attorney-Advisor, at (202) 233-9151, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St. SW., Washington, DC 20460, or the Acid Rain Hotline at (202) 233-9620.

SUPPLEMENTARY INFORMATION: If no significant, adverse comments are timely received, no further activity is contemplated in relation to this proposed rule and the direct final rule in the final rules section of this Federal Register will automatically go into effect on the date specified in that rule. If significant, adverse comments are timely received on any provision, that provision of the direct final rule will be withdrawn and all public comment received on that provision will be addressed in a subsequent final rule based on the relevant portions of this proposed rule. Because the Agency will not institute a second comment period on this proposed rule, any parties interested in commenting should do so during this comment period.

For further supplemental information, the detailed rationale, and the rule provisions, see the information provided in the direct final rule in the final rules section of this **Federal Register**.

List of Subjects in 40 CFR Part 72

Environmental protection, Acid rain program, Air pollution control, Compliance plans, Electric utilities, Permits, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: March 31, 1995.

Carol M. Browner,

Administrator, Environmental Protection Agency.

[FR Doc. 95-8602 Filed 4-10-95; 8:45 am]

BILLING CODE 6560-50-P

FOR FURTHER INFORMATION CONTACT: Daniel A. Meer, Chief, Rulemaking Section, Air and Toxics Division, U.S. Environmental Protection Agency, Region IX, 75 Hawthorne Street, San Francisco, CA 94105, Telephone: (415) 744–1185.

SUPPLEMENTARY INFORMATION

Background

On June 2, 1994 in 59 FR 28503 EPA proposed to approve the following rules into the California SIP: SCAQMD's Rule 1106.1, Pleasure Craft Coating Operations, and Rule 109, Recordkeeping for Volatile Organic Compound Emissions. Rule 1106.1 was adopted by SCAQMD on May 1, 1992, and Rule 109 was adopted on March 6, 1992. Both rules were submitted by the California Air Resources Board (CARB) to EPA on September 14, 1992. These rules were submitted in response to EPA's 1988 SIP-Call and the CAA section 182(a)(2)(A) requirement that nonattainment areas fix their reasonably available control technology (RACT) rules for ozone in accordance with EPA guidance that interpreted the requirements of the pre-amendment Act. A detailed discussion of the background for each of the above rules and nonattainment areas is provided in the NPR(s) cited above.

EPA has evaluated the above rules for consistency with the requirements of the CAA and EPA regulations and EPA interpretation of these requirements as expressed in the various EPA policy guidance documents referenced in the NPR(s) cited above. EPA has found that the rules meet the applicable EPA requirements. A detailed discussion of the rule provisions and evaluations has been provided in (59 FR 28503 and in technical support documents (TSDs) available at EPA's Region IX office (TSDs dated February 16, 1993, Pleasure Craft Coating Operations and February 24, 1993, Recordkeeping for Volatile Organic Compound Emissions).

Response to Public Comments

A 30-day public comment period was provided in 59 FR 28503. EPA received no comments.

EPA Action

EPA is finalizing action to approve the above rules for inclusion into the California SIP. EPA is approving the submittal under section 110(k)(3) as meeting the requirements of section 110(a) and Part D of the CAA. This approval action will incorporate these rules into the federally approved SIP. The intended effect of approving these rules is to regulate emissions of VOCs in accordance with the requirements of the CAA.

Nothing in this action should be construed as permitting or allowing or establishing a precedent for any future request for revision to any state implementation plan. Each request for revision to the state implementation plan shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

The Office of Management and Budget (OMB) has exempted this action from review under Executive Order 12866.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Hydrocarbons, Incorporation by reference, Intergovernmental relations, Ozone, Reporting and recordkeeping requirements, Volatile organic compounds.

Note: Incorporation by reference of the State Implementation Plan for the State of California was approved by the Director of the Federal Register on July 1, 1982.

Dated: March 28, 1995.

Felicia Marcus,

Regional Administrator.

Part 52, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

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

Authority: 42 U.S.C. 7401–7671q.

Subpart F—California

2. Section 52.220 is amended by adding paragraph (c)(189)(i)(A)(*6*) to read as follows:

§ 52.220 Identification of plan.

* * * * *

(c) * * *

(189) * * *

(i) * * *

(A) * * *

(*6*) Rule 109 adopted on March 6, 1992, and Rule 1106.1 adopted on May 1, 1992.

* * * * *

[FR Doc. 95–9042 Filed 4–12–95; 8:45 am]

BILLING CODE 6560–50–P

40 CFR Part 76

[AD–FRL–5186–5]

RIN 2060–AD45

Acid Rain Program: Nitrogen Oxides Emission Reduction Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule; response to court remand.

SUMMARY: The EPA is today issuing this final rule in response to a remand by a U.S. Court of Appeals. The rule reinstates emission limitations for nitrogen oxides (NO_X) from coal-fired utility units under section 407 of the Clean Air Act ("the Act"). The emission limitations for NO_X, along with emission limitations for sulfur dioxide from utility plants, will reduce acidic deposition and its serious adverse effects on natural resources, ecosystems, materials, visibility, and public health.

On March 22, 1994, EPA promulgated a rule establishing NO_X emission limitations. The rule established emission limits generally achievable using "low NO_X burner technology" and established a procedure for obtaining an alternative emission limitation (AEL) if a unit could not achieve the prescribed limit using such technology. On November 29, 1994, the U.S. Court of Appeals for the District of Columbia Circuit ruled that the definition of "low NO_X burner technology" in the March 22, 1994 rule exceeded EPA's statutory authority. The Court vacated the rule and remanded it to the Agency for further proceedings. On March 28, 1995, EPA and environmental and utility-industry parties signed an agreement addressing the March 22, 1994 regulations, including issues raised by the Court's remand.

Based on the Court's decision and a review of the record, the Agency is now revising the March 22, 1994 regulations. The low-NO_X-burner-technology definition is revised to comply with the Court's decision. Other provisions concerning the compliance date for Phase I NO_X emission limitations, AELs, and plans for averaging NO_X emissions of two or more units are also revised. In general, the revisions reduce compliance requirements, extend the compliance date, and increase compliance flexibility. The rule revisions are issued as a direct final rule because they are consistent with the Court's decision and no adverse comment is expected. The revisions are also consistent with the March 28, 1995 agreement.

EFFECTIVE DATE: This direct final rule will be effective on May 23, 1995 unless significant, adverse comments are received by May 15, 1995. If significant, adverse comments are timely received on any portion of the direct final rule, that portion of the direct final rule will be withdrawn through a notice in the **Federal Register**.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of May 23, 1995.

ADDRESSES: Docket No. A–92–15, containing information considered during development of the promulgated standards and requirements, is available for public inspection and copying between 8:30 a.m. and 3:30 p.m., Monday through Friday, at EPA's Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying. Additional data and information pertaining to the rule may be found in Docket No. A–90–39.

FOR FURTHER INFORMATION CONTACT: Peter Tsirigotis, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street SW., Washington, DC 20460 (for technical matters) at (202) 233–9620; or Dwight C. Alpern (same address) (for legal matters) at (202) 233–9151.

SUPPLEMENTARY INFORMATION: The information in this preamble is organized as follows:

I. Background

A. Purpose of the Acid Rain NO_x Program

The purpose of the Acid Rain NO_x emission reduction program is to reduce the adverse effects of acidic deposition on natural resources, ecosystems, visibility, materials, and public health by substantially reducing annual emissions of NO_x from coal-fired electric utilities. 42 U.S.C. 7651(a)(1). NO_x, along with sulfur dioxide, is a principal precursor of acidic deposition.

Although sulfate deposition is considered to be the major contributor to long-term aquatic acidification, nitric acidic deposition plays a dominant role in the "acid pulses" associated with the fish kills observed during the springtime meltdown of the snowpack in sensitive watersheds. Furthermore, the atmospheric deposition of NO_x is a substantial source of nutrients that damage estuaries, such as the Chesapeake Bay, by causing algae blooms and anoxic conditions. Nitrogen dioxide and particulate nitrate also contribute to pollutant haze. Moreover, acidic deposition and ozone (formed by the photochemical reaction of NO_x and volatile organic compounds) contribute to the premature weathering and corrosion of building materials such as architectural paints and stones.

Electric utilities are a major contributor to NO_x emissions nationwide: in 1980, they accounted for 30 percent of total NO_x emissions and, by 1990, their contribution rose to 38 percent of total NO_x emissions. Approximately 80 percent of electric utility NO_x emissions come from coal-fired plants of the type addressed by section 407 of the Act.

B. Statutory Framework

Section 407(b)(1) of the Act requires the Administrator to establish NO_x emission limitations for two types of coal-fired utility boilers ("Group 1" boilers): (1) Tangentially fired boilers; and (2) dry bottom wall-fired boilers other than units applying cell burner technology ("wall-fired boilers"). The Act specifies the maximum emission limits (often referred to as "presumptive" emission limits or limits) for these Group 1 boilers: 0.45 lb/mmBtu for tangentially fired boilers; and 0.50 lb/mmBtu for wall-fired boilers. If the Administrator finds that the presumptive limits cannot be achieved using "low NO_x burner technology," the Administrator may set less stringent limitations. 42 U.S.C. 7651f(b)(1). A Phase I coal-fired utility unit with a Group 1 boiler must comply with the promulgated annual NO_x emission limitation on the later of January 1, 1995 or the date the unit is required to meet SO_2 emission reduction requirements under section 404(d) of the Act (*id.*).

Section 407(d) provides a mechanism by which a utility unit may receive an AEL less stringent than the applicable limitation established under section 407(b)(1) for Group 1 boilers. In order to receive an AEL, the owner or operator of the unit must demonstrate that it cannot meet the applicable limitation using properly installed "low NO_x burner technology" designed to meet the limitation. 42 U.S.C. 7651f(d). If the owner or operator makes the necessary showings, then an AEL will be established that does not require "any additional control technology beyond low NO_x burners." 42 U.S.C. 7651f(d).

Section 407(d) also provides that EPA may grant the owner or operator of a Phase I coal-fired utility unit subject to section 407(b)(1) a 15-month extension from the January 1, 1995 compliance deadline. Such an extension may be granted if the technology necessary to meet the promulgated NO_x emission limitation is not in adequate supply to enable its installation and operation at the unit, consistent with system reliability, by January 1, 1995. Section 407(d) specifies the process the Administrator must use in authorizing the Phase I extension.

A more detailed discussion of the statutory framework is set forth at 59 FR 13538–13539 (March 22, 1994).

C. EPA's Rulemaking

As discussed above, the term "low NO_x burner technology" plays an important role in section 407 of the Act. There has been substantial controversy as to whether Congress intended "low NO_x burner technology" to be equivalent to "low NO_x burners" and whether "low NO_x burner technology" includes all forms of combustion air staging or only staging at the burner. On November 25, 1992, EPA published a proposed rule establishing NO_x emission limitations for coal-fired utility units under section 407(b)(1) of the Act and other requirements and procedures for all coal-fired units subject to Phase I and Phase II of the Acid Rain Program (57 FR 55632–55683). In recognition of the controversy surrounding the definition of low NO_x burner technology, the proposed rule contained two regulatory options and an alternative approach for defining that term. Option 1 defined low NO_x burner technology as low NO_x burners incorporating overfire air for wall-fired boilers and as low NO_x burners incorporating separated overfire air (e.g., LNCFS 2 and LNCFS 3) for tangentially fired boilers (57 FR 55642). Option 2 defined low NO_x burner technology as low NO_x burners incorporating separated overfire air for tangentially fired boilers, but excluded overfire air from the definition for wall-fired boilers (*id.*). In addition to the two options set forth, EPA solicited comment on a third approach. This approach was endorsed by the Utility Air Regulatory Group (UARG) (a group made up of utilities that subsequently challenged the March 22, 1994 final rule) and the U.S. Department of Energy (DOE). Under the third approach, low NO_X burner technology was defined as excluding both overfire air for wall-fired boilers and separated overfire air for tangentially fired boilers (57 FR 55644–55645).

On March 22, 1994, EPA published the final NO_X rule (59 FR 13538–13580). In that rule, EPA adopted the Option 1 definition of low NO_X burner technology after considering the chemical process of low NO_X combustion, the history and application of low NO_X combustion technology, Congress' intent in section 407 of the Act, and the actual application of NO_X control technology.

II. The Court's Decision

Following issuance of the March 22, 1994 rule, numerous utilities and the National Coal Association petitioned for judicial review of the rule. The two main issues raised on appeal were: whether EPA's definition of low NO_X burner technology was lawful; and whether EPA was obligated to extend the January 1, 1995 compliance date prescribed in section 407 of the Act because EPA did not issue the rules by the May 15, 1992 issuance date required by section 407.

On November 29, 1994, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision on the petitioners' first issue. The Court held that "[t]he statutory text, structure, and history of section 407 * * * support the 'unmistakable conclusion' that Congress unambiguously intended the term 'low NO_X burner technology' to encompass only low NO_X burners, not overfire air" (*Alabama Power Co.* v. *U.S. EPA*, No. 94–1170 (D.C. Cir, 1994) slip op. at 12). The Court explained that under the AEL provision, "Congress did not intend to require utilities to consider the 'full range of low NO_X combustion technologies' because it *expressly* provided that utilities not be required to install or use any equipment beyond low NO_X burners in their efforts to comply with NO_X emission limits" (*id.* at 11). After concluding that EPA had exceeded its statutory authority, the Court vacated the March 22, 1994 rule and determined that the petitioners' second issue on the compliance deadline was moot.

III. EPA's Response to the Court's Decision

A. Changes to the March 22, 1994 Rule

1. Definitions

Low NO_X burners and low NO_X burner technology. Because the Court determined that, in defining low NO_X burner technology in the March 22, 1994 rule, the Agency exceeded its authority under section 407 of the Act, the revised rule changes the definition of the terms, "low NO_X burners and low NO_X burner technology," in § 76.2. The Court determined that low NO_X burner technology encompasses "only low NO_X burners" (*Alabama Power*, slip op. at 12). The Agency is removing from the March 22, 1994 definition the language that is inconsistent with the Court's determination. In particular, the revised rule eliminates the language stating that low NO_X burner technology includes "any combination of coal and air nozzles ports * * * not restricted to location within the boiler, including * * * NO_X ports, overfire air ports, or staged combustion ports" (59 FR 13565). Other related language (e.g., "at points downstream of the initial flame" (*id.*)) in the March 22, 1994 definition is also removed.

The removed language is replaced by new language explaining that the new definition includes the staging of combustion air using air nozzles or registers located inside any boiler waterwall[1] hole that includes a burner. Additional new language explains that the definition excludes the staging of combustion air using air nozzles or ports located outside any boiler waterwall hole that includes a burner. The new language implements, for both wall- and tangentially-fired boilers, the Court's holding that low NO_X burner technology includes only low NO_X burners.

For wall-fired boilers, two types of NO_X combustion controls have been used: (1) Advanced burner retrofits for reducing NO_X formation ("burner retrofits");[2] and (2) combustion air staging (i.e., "overfire air" for wall-fired boilers) (57 FR 55640). Burner retrofits must be custom-designed for each boiler and the ease of retrofitting varies from boiler to boiler:

> In some cases (of burner retrofits), burner openings must be enlarged via remolding the refractory material at the burner exit or by enlarging the hole (*not* cutting holes in the boiler tubes). If enlargement of the hole requires that tubes be cut and bent slightly to accommodate the burner, however, this procedure does not affect the boiler water circulation since the tubes have been previously bent. The circulation design takes bends into account during initial boiler design. By contrast, cutting holes as required for the addition of (overfire air) affects the boiler circulation. (Docket Item VIII–A–2, Reply Brief of Petitioners, August 29, 1994, Exhibit 1.)

Unlike burner retrofits, overfire air for wall-fired boilers involves diverting some combustion air from waterwall openings that include a burner and injecting the air above the top burner level. This generally requires the cutting of entirely new holes in the waterwall above the highest burners (*id.*; 57 FR 55640).

The new low-NO_X-burner-technology definition, as applied to wall-fired boilers, encompasses all burner retrofits that are essentially within an existing waterwall hole. Such retrofits may involve minor modifications (e.g., of pressure parts or refractory material) to the existing waterwall hole as necessary to accommodate the retrofit essentially within the hole. The new definition excludes all overfire air as applied to wall-fired boilers. This definition meets the Court's requirement that only burners be considered; nothing in the Court's decision excludes retrofit burners requiring minor waterwall modifications. *See, e.g.*, slip op. at 5 footnote 3 (discussing low NO_X burners).

For tangentially fired boilers, all commercially available systems for reducing NO_X formation involve a staged combination of coal and air (57 FR 55641). Three types of control systems for tangentially fired boilers were discussed in detail in the preamble to proposed part 76: (1) The replacement of the original coal and air nozzle array in each corner of the boiler with a new low NO_X configuration of coal and air nozzles and the installation of air nozzles at the upper end of each waterwall hole that contains the new coal and air nozzle array ("LNCFS 1");[3]

[1] Waterwalls are panels of water tubes running along the length of a boiler. These tubes carry water or steam. Water in these tubes is converted into steam through the heat transfer between combustion gas and this water.

[2] Typical designs of burner retrofits include upgraded air registers that allow for better control of combustion air and a redesigned burner tip. Burner retrofits achieve controlled fuel and air mixing in the flame. This arrangement results in rapid devolatilization and combustion of nitrogen-containing volatile matter under conditions of limited availability of oxygen, with the result that the formation of fuel NO_X is suppressed. The arrangement also results in combustion of air and coal char with a cooler flame than the flame of conventional burners, which suppresses thermal NO_X formation (59 FR 13541).

[3] Several other low NO_X burner designs also use combustion air staging in the waterwall hole where

Continued

(2) the installation of air nozzles in a new air nozzle assembly above the waterwall hole that contains the original coal and air nozzle array in each corner ("LNCFS 2"); and (3) the replacement of the original coal and air nozzle array with a new low NO_X configuration in each corner and the installation of both air nozzles at the upper end of each waterwall hole containing the new array and a new air nozzle assembly above each waterwall hole ("LNCFS 3") (*id.*).

As is the case with wall-fired retrofit burners, LNCFS 1 is custom-designed for each boiler and may require modifications to the existing waterwall hole (59 FR 13546–13547). Retrofit burners and LNCFS 1 respectively involve the injection of air through registers or nozzles located in a waterwall hole that includes the burner: In the case of wall-fired boilers, the air registers are in the burner retrofit itself while in the case of tangentially fired boilers, the air nozzles are in the hole with the coal and air nozzle array.

In contrast with LNCFS 1, LNCFS 2 and LNCFS 3 involve injecting combustion air above the coal and air nozzle array in each corner through a new air nozzle assembly requiring an entirely new waterwall hole above the array (57 FR 55641). The new low-NO_X-burner-technology definition, as applied to tangentially fired boilers, includes the applications of LNCFS 1 (and other low NO_X burner designs)[4] that are essentially within the existing waterwall hole. The included applications may involve minor modifications (e.g., of pressure parts or refractory material) to the existing waterwall hole as necessary to accommodate the NO_X emission controls essentially within the existing hole. The new definition excludes all applications of separated overfire air, e.g., LNCFS 2 and LNCFS 3. This is consistent with the Court's holding in that, as discussed above, LNCFS 1 for tangentially fired boilers is analogous to retrofit burners for wall-fired boilers and thus falls within the Court's prescription that "low NO_X burner technology" be limited to low NO_X burners only.

The Agency notes that its new definition is in essence the same as the definition set forth in the preamble of the November 25, 1992 proposed rule as an alternative to Options 1 and 2 (57 FR 55644–55645). The alternative approach, like the new definition adopted today, excluded overfire air for wall-fired boilers and excluded LNCFS 2 and LNCFS 3 for tangentially fired boilers. The utilities described the alternative approach as involving "the direct replacement of the original equipment manufacturer's coal burners (with low NO_X burners) without major new waterwall penetrations or parts" (Docket Item IV–D–111 at 74). The utilities also noted that their definition under the alternative approach—like the definition in the revised rule—includes "burners[-]only technologies that have recently begun to be offered commercially" for tangentially fired boilers, i.e., the low NO_X burner designs described in footnote 3 above (*id.* at 73). In comments on the November 25, 1992 proposal, the utilities and DOE supported the alternative approach as being consistent with section 407 of the Act (Docket Items IV–D–2 at 1–2 and IV–D–111 at 73–84).

Other defined terms. In light of the new low-NO_X-burner-technology definition adopted today, two other definitions in § 76.2 of the March 22, 1994 rule are now superfluous and are eliminated in the revised rule.[5] In particular, the new low-NO_X-burner-technology definition itself describes what forms of air staging are included or not included in the definition, and, as discussed below, references in other sections of part 76 to "combustion air staging" have been removed. Consequently, there is no need for the definition of "combustion air staging". See 59 FR 13564. Further, the definition of "low NO_X coal and air nozzles" is unnecessary because that term is no longer used in part 76. See 59 FR 13565.

2. Date for Compliance with NO_X Emission Limitations

The revised rule changes the date in § 76.5(a) on which a Phase I unit with a Group 1 boiler begins to be subject to the NO_X emission limitations. Under the March 22, 1994 rule, such a Phase I unit must begin compliance with NO_X emission limitations on the later of January 1, 1995 or the date the unit becomes subject to SO_2 emission reduction requirements under section 404(d) of the Act. Under the revised rule, the January 1, 1995 date is changed to January 1, 1996. Analogous changes in the compliance date are made in §§ 76.1(d) and 76.5(d).[6]

The change in the compliance date is necessary because of the delay in the repromulgation of the NO_X emission limitations. The Court vacated the March 22, 1994 rule on November 29, 1994, only 32 days prior to the compliance deadline. The Court added that the reissued NO_X emission limitations "will undoubtedly take effect after the statutory deadline [for compliance] of January 1, 1995." *Alabama Power,* slip op. at 13. Moreover, the Court noted "the agency's representation at oral argument that it would be inclined to exercise its enforcement discretion in favor of the utilities in order to account for delay in the rulemaking process" (*id.*).

As correctly predicted by the Court, today's revised rule reinstating NO_X emission limitations takes effect after January 1, 1995, despite the Agency's efforts to expedite the rulemaking process. Maintaining the January 1, 1995 deadline for compliance with the NO_X emission limitations would mean that the limitations under the revised rule would have to be applied prior to their effective date.

Not only would this approach raise questions of retroactivity, but also the Agency is concerned about the lack of any lead time between promulgation of NO_X emission limitations and the beginning date for compliance. Under these circumstances, the Agency must determine what Congress would have intended had it addressed the problem of issuance of the NO_X emission limitations after January 1, 1995. Section 407 required the Agency to issue final NO_X regulations within 18 months of enactment of title IV (i.e., by May 15, 1992) and required compliance with such regulations to begin on January 1, 1995. Although these are independent requirements and, the Agency maintains, no specific lead time between rule promulgation and compliance was mandated, it is reasonable to conclude that Congress intended that there be some lead time. Retaining a January 1, 1995 compliance deadline would result in no lead time at all.

Further, the Agency recognizes that the promulgation of the March 22, 1994 low-NO_X-burner-technology definition and the Court's decision vacating the March 22, 1994 rule may have

the coal and air nozzle array is located. Some of these are : Foster Wheeler's T-fired/Split Flame (TF/SF) burner; and International Combustion Ltd.'s FAN burner (Docket Item IV–D–111, Comments of the Utility Air Regulatory Group on EPA's Proposed Rules on Nitrogen Oxides Reduction Program, February 8, 1993, at 28, 30 and 115). Both of these designs incorporate air nozzles at the upper end of the waterwall hole that contains the new coal and air nozzle array in each corner of the boiler. Neither, however, incorporates any staging that utilizes injection of air through separate holes (e.g., separated overfire air ports) in the waterwall and that therefore is external to the waterwall hole containing the burner (*id.* at 27).

[4] See footnote 3 above.

[5] As discussed below, the definition of "alternative technology" is also revised.

[6] The language in § 76.5(d) is also revised to make it consistent with § 76.5(a) and clarify that a unit under § 76.5(d) may seek to use a compliance option in §§ 76.10, 76.11, or 76.12.

engendered some uncertainty and confusion on the part of utilities concerning their regulatory obligations. This further supports a change in the January 1, 1995 compliance deadline. However, the Agency notes that Phase I units generally proceeded in good faith to take the necessary steps to comply with the March 22, 1994 rule. These steps included obtaining a permit to operate and, where necessary, installing NO_X control equipment, including low NO_X burners. Of the 175 Phase I units with Group 1 boilers on Table A of section 404, all submitted NO_X compliance plans by May 6, 1994 and only 31 requested a compliance date extension.[7] Since complying with the revised rule will, in general, require the same or less effort than the industry has already undertaken, the extension until January 1, 1996 is judged to be reasonable and appropriate.

The establishment of January 1, 1996 as the compliance deadline also reflects the fact that title IV of the Act created an annual program with regard to both SO_2 and NO_X emissions reductions. Units must comply with SO_2 emission limitations by emitting no more SO_2 in a year than is authorized by the number of allowances "held for that unit for that year." 42 U.S.C. 7651b(g). Similarly, emission limitations for NO_X are annual: The generic limits established under section 407(b) are "annual allowable emission limitations"; AELs under section 407(d) are emission rates that can be met "on an annual basis"; and emissions averaging plans under section 407(e) limit NO_X emissions using both "alternative contemporaneous annual emission limitations" and a "Btu-weighted average annual emission rate." Adopting January 1, 1996 as the compliance deadline preserves the annual nature of the Acid Rain Program.

The revised rule also changes language in the March 22, 1994 rule concerning the date for compliance with any revised emission limitations for Group 1 boilers that may be adopted under section 407(b)(2) of the Act. The March 22, 1994 rule states that Group 1, Phase II units must comply with any revised Group 1 emission limitations starting on January 1, 2000. Because EPA has not determined whether to revise the Group 1 emission limitations under section 407(b)(2), it is unnecessary to state, in the rule at this time, the compliance date for such revised limitations. If and when the limitations are revised, the rule will be amended to add both the limitations and the compliance date. Sections 76.5(g) and 76.10(f)(1)(iii) are revised to remove that compliance date.

3. Alternative Emission Limitations

In order to ensure that § 76.10 is consistent with the new definition of the term "low NO_X burner technology," all phrases in the section that elaborated on that term are eliminated. In particular, in §§ 76.10(a)(1) and (2) of the March 22, 1994 rule, the term "low NO_X burner technology" is followed by phrases such as: "including separated overfire air"; "incorporating both close-coupled and separated overfire air"; or "incorporating combustion air staging above the top burner level" (59 FR 13567–13568). The revised rule excludes all of these phrases and is reworded as necessary to reflect their removal. As a result of these changes, units with Group 1 boilers may apply for AELs if they are unable to meet applicable emission limitations using low NO_X burner technology under the new definition in § 72.2.[8]

The revised rule also adds that units with tangentially fired boilers may seek AELs where they cannot meet the applicable emission limitations using separated overfire air. In order to comply with the March 22, 1994 low-NO_X-burner-technology definition, which was then in effect and included close-coupled and separated overfire air, some units installed only separated overfire air. The record information to date indicates that separated overfire air alone is at least as effective in reducing NO_X emissions as low NO_X burner technology as applied to tangentially fired boilers. See Docket Item IV–A–10, Background Document for RIA of NO_X Regulations, appendix A at 21. The Agency therefore maintains that such units should not be disqualified from seeking an AEL because of their efforts to comply with the March 22, 1994 rule. Sections 76.10(a)(1) and (2)(i)(A) are revised to allow such units to seek AELs.

For similar reasons, the definition of "alternative technology" set forth in § 76.2 is revised. Under the revised rule, "alternative technology" is NO_X emission control technology other than low NO_X burner technology but does not include overfire air for wall-fired boilers and separated overfire air for tangentially fired boilers. Under §§ 76.10(a) and (e)(11), a unit using alternative technology, in addition to or in lieu of low NO_X burner technology, to reduce NO_X emissions must show an annual average emissions reduction of greater than 65 percent in order to qualify for an AEL. The revision of the alternative-technology definition excludes units with tangentially fired boilers applying separated overfire air from the 65-percent reduction requirement.[9] This avoids putting at a disadvantage, for purposes of obtaining AELs, units that may have installed separated overfire air because of the March 22, 1994 low-NO_X-burner-technology definition.

Moreover, certain dates in § 76.10(c)(1), concerning the submission of petitions for an AEL demonstration period, and in § 76.10(f)(1), concerning approved AEL demonstration periods, are changed. See 59 FR 13568 and 13570. These revisions reflect the change in the compliance deadline from January 1, 1995 to January 1, 1996.

Finally, certain provisions, concerning information included in petitions for AEL demonstration periods and for final AELs, in §§ 76.14 and 76.15 of the March 22, 1994 rule refer to combustion air or air flow through "overfire air ports" or "combustion air staging ports." Since low NO_X burner technology now excludes air nozzles or ports located outside a waterwall hole that includes a burner, these references are no longer appropriate. The provisions have been modified to apply

[7] Twenty-five units applied for a 2-year Phase I extension for SO_2 under § 72.42 (which automatically granted them a 2-year NO_X extension), and 6 units applied for a 15 month Phase I NO_X compliance extension under § 76.12.

[8] Since low NO_X burner technology does not include air nozzles or ports located outside of a waterwall hole that includes a burner, provisions in § 76.10 concerning the technical feasibility of installing such air nozzles or ports are irrelevant. Consequently, the March 22, 1994 provisions in §§ 76.10(a)(3) and (d)(4) are entirely eliminated. See 59 FR 13568–13569. The revised rule also reflects the removal of any reference to these eliminated provisions and the renumbering that results from their elimination. See 59 FR 13568–69 and 13574. In addition, the requirement in § 76.10(g)(1)(ii)(C) that the designated representative revise the AEL demonstration period plan is changed to apply only when the owner or operator identifies *operating* modifications (whether for the boiler or the NO_X emission control system) that improve NO_X reductions. Consistent with § 76.10(a)(2)(iii)(B), this does not require revision of the plan to include operating modifications that would prevent the boiler or NO_X control system from being operated in accordance with the bid and design specifications on which the design of the NO_X control system is based. Plan revision is no longer required for all possible equipment modifications or upgrades since they could be outside the new low-NO_X-burner technology definition. See 59 FR 13570–13571.

[9] In order to avoid repeating in other sections the NO_X control technology requirements set forth in § 76.10(a)(2) for qualifying for an AEL (e.g., that a Group 1 boiler install low NO_X burner technology, alternative technology, or, for a tangentially fired boiler, separated overfire air), the references in §§ 76.10(d)(8) and (e)(2)–(4) and 76.15(c) to specific technologies are replaced by a general reference to the "installed NO_X emission control system" or "NO_X emission control system." Such a system must, of course, meet the requirements in § 76.10(a)(2). In addition, § 76.10(e)(2) is also revised to make it consistent with § 76.10(d)(8).

only to tangentially fired boilers (which may use close-coupled overfire air) and to refer to the "distribution of combustion air" within the "NO_X emission control system." See 59 FR 13574 (§ 76.14(a)(2)(i)) and 13575 (§ 76.15(b)(3) and (d)(2)).[10]

As a result of these changes, the revised rule complies with the Court's decision. The rule provides that, in applying for an AEL, the designated representative for an affected Group 1 unit must demonstrate that the unit cannot meet the presumptive emission limit using properly installed and operated low NO_X burner technology as redefined (or alternative technology or, for tangentially fired boilers, separated overfire air) that is designed to meet the presumptive limit. The designated representative is not required to attempt to meet the presumptive limit using low NO_X burners plus overfire air for wall-fired boilers or separated overfire air for tangentially fired boilers. Rather, in keeping with the Court's decision, the designated representative may base the petition for an AEL on the use of only low NO_X burners. Nothing in the Court's decision mandates any further changes in the AEL provisions.

4. NO_X Averaging Plans

Section 76.11 is revised to change the provisions concerning compliance on an individual basis and on a group basis with the emission limitations in NO_X averaging plans and to clarify language in the formulas implementing the requirements of such plans.

Under § 76.11(d) of the March 22, 1994 rule, units governed by a NO_X averaging plan must comply with both individual-unit limits "and", where applicable, a group emission requirement. 59 FR 13572 (§ 76.11(d)(1)(i)(B)). An averaging plan must state individual-unit limits for all units in the plan, i.e., an alternative contemporaneous annual emission limitation and, in most cases, an annual heat input limit. The formula for setting the individual-unit limits is Equation 1 in § 76.11(a)(6). Each unit's actual annual average emission rate must not exceed that unit's alternative contemporaneous annual emission limitation. Further, if the alternative contemporaneous annual emission limitation is less stringent than the applicable emission limitation, the unit's actual annual heat input must not exceed the unit's annual heat input limit. If the alternative contemporaneous annual emission limitation is more stringent, the unit's heat input must not be less than the heat input limit.

The March 22, 1994 rule also provides that if one or more of the units under the plan fail to meet the individual-unit limits, there must be a showing that the entire group of units under the plan complies with a group emission requirement. The group emission requirement is met where the actual Btu-weighted annual average emission rate for the units in the plan does not exceed the Btu-weighted annual average emission rate for these units if they had operated in compliance with the applicable emission limitation in §§ 76.5, 76.6, or 76.7. The formula for determining group compliance is Equation 2 in § 76.11(d)(1)(ii)(A).

Section 76.11(d)(2) of the March 22, 1994 rule addresses liability where units under the NO_X averaging plan fail to meet any of the requirements of the plan, including the individual-unit limits and the group emission requirement. Under § 76.11(d)(2)(i), the owners and operators of each unit under the plan are liable for any violations of the plan (or of § 76.11) by any unit under the plan. Such liability expressly includes the excess emissions penalty under 40 CFR part 77 and section 411 of the Act and penalties under section 113 of the Act. The only exception to the liability provision in § 76.11(d)(2)(i) is that if the group showing of compliance under § 76.11(d)(1)(ii) is made, then no unit under the plan is subject to the excess emissions penalty. Regardless of whether the group showing of compliance (which is for purposes of excess emissions) is made, the March 22, 1994 rule does not exempt any unit under the plan from liability under section 113 for violation of the individual-unit limits.

In contrast with the March 22, 1994 rule, the revised rule provides that if one or more units fail to meet the individual-unit limits but there is a showing of group compliance for the year, then all units in the plan will be deemed to be in compliance for the year with the individual-unit limits. With regard to their NO_X emissions for the year, all units therefore will be in compliance with the averaging plan and have no potential liability for violation of the plan or part 76. Further, none of the units will have excess emissions for the year under part 77.

The Agency has received public comment to the effect that this revised approach, which was proposed in the original November 25, 1992 proposed NO_X rule, is more consistent with the purposes of section 407 than the approach adopted in the March 22, 1994 rule. Neither section 407(e) nor the legislative history specifically address this matter. However, section 407(e) states that individual units' alternative contemporaneous annual emission limitations must "ensure that the units' actual annual NO_X emission rate" averaged over the units in question does not exceed the "Btu-weighted annual average emission rate for the same units" if they had met the applicable emission limitations under section 407(b). 15 U.S.C 7651f(e). That goal is satisfied where units fail to meet the individual-unit limits in the NO_X averaging plan but can show group compliance with the plan.

Further, even though the March 22, 1994 rule relieves units in such circumstances from liability for excess emissions, the units are still potentially liable for civil penalties, which may be enforceable through Agency action or citizen suits under sections 113 and 304 of the Act. This potential liability is sufficiently significant that a utility with a NO_X averaging plan may, in effect, be forced to comply unit-by-unit with the individual-unit limits even if the group emission requirement could be met without meeting all the individual-unit limits. The individual-unit limits can restrict the utility's flexibility, for example, in dispatching the units in the plan. In order to minimize the likelihood of violating individual-unit limits, some designated representatives have submitted Phase I NO_X averaging plans that set alternative contemporaneous emission limitations equal to the presumptive limits in § 76.5 and that specify no heat input limits. However, under such plans, the individual-unit limits can still restrict the utility's flexibility to choose which units in the plan will be retrofitted with NO_X emission control systems and what types of NO_X emission control systems will be used. The Agency is concerned that the net result of such lack of flexibility is that designated representatives will be encouraged to seek AELs for more units, rather than attempting to average units with higher NO_X emissions with units with lower NO_X emissions. Not only is the case-by-case process of setting AELs administratively burdensome for utilities and the Agency, but also the Agency is concerned that total NO_X emissions are likely to be higher the greater the number of units with AELs.

The Agency concludes that removing the requirement to meet individual-unit limits when there is group compliance

[10] Sections 76.15(a), (b), and (d) are also revised to state, consistent with §§ 76.10(d)(13) and 76.14(a)(2)(v), that the owner or operator "may" use for tests and procedures set forth in § 76.15. Further, the language in § 76.15(b)(6) is clarified, and § 76.15(d)(3) is revised to refer more generally to optimization of the combustion process and to cite burner balancing as an example.

under a NO_x averaging plan is a reasonable interpretation of section 407(e) and better implements that provision. Consequently, § 76.11(d)(1)(ii) is revised to state that when the units in a NO_x averaging plan show compliance with the group emission requirement in § 76.11(d)(1)(ii)(A) for a given year, the units will be deemed to comply for that year with their individual emission limitations and heat input limits. Since units meeting group compliance are thereby in compliance with both the individual-unit and group emission requirements of the plan, there is no need to state separately that group compliance relieves the units of any penalties for excess emissions. Section 76.11(d)(2)(ii) is therefore eliminated.[11]

Sections 76.11(a) (6) and (7) and (d)(1)(ii) (A) and (B) are also revised to clarify the formulas (Equations 1 and 2) that govern the selection of individual-unit limits and the showing of group compliance. The language in these sections explaining what "applicable emission limitation" to use in Equations 1 and 2 is confusing. The revised rule clarifies that the limitation to be used in Equations 1 and 2 is the applicable emission limitation for each respective unit in §§ 76.5, 76.6, or 76.7. Consistent with that approach, a unit with an AEL must use the applicable emission limitation in §§ 76.5, 76.6, or 76.7 rather than the AEL. The only exception is that an early election unit, which elects to meet NO_x emission limitations in Phase I but is allowed to participate in a NO_x averaging plan only in Phase II, must use the most stringent applicable limitation in §§ 76.5 or 76.7 (i.e., 0.45 lb/mmBtu or 0.50 lb/mmBtu depending on whether the unit's boiler is wall-fired or tangentially fired) or, if the limitation is revised and made more stringent for Phase II under section 407(b)(2), the revised limitation applicable to the boiler type.

In order to simplify the language in §§ 76.11(a)(7) and (d)(1)(ii)(B) in the March 22, 1994 rule, the references to Phase II units are removed. To capture the concept in the March 22, 1994 provisions that Phase II units cannot participate in averaging plans before January 1, 2000, § 76.11(a)(1) is revised to state that a unit in an averaging plan in Phase I must be a Phase I unit with a Group 1 boiler.

EPA notes that it has received public comments concerning the use of a single NO_x averaging plan for units of two or more operating companies (also referred to as utility systems) that are subsidiaries of a single holding company. In such a case, the operating companies would designate the same designated representative (probably someone at the holding company level) for their units in order to meet the common designated representative requirement for a NO_x averaging plan. Each operating company could still designate its own alternate designated representative. Concern was raised that the designated representative at the holding company level may not be readily accessible and that operating companies may need the flexibility of having two persons at the operating company level with authority to act for the designated representative. The Agency is currently reviewing this matter and, in light of the public comments, will propose, in a future rulemaking, revisions to 40 CFR part 72 that would allow designation of a second alternate designated representative for units under certain limited circumstances. Such circumstances could be where: The unit's utility system is a subsidiary of a holding company with two or more utility-system subsidiaries in two or more states; and, in order to use a NO_x averaging plan involving units of two or more such subsidiaries, all the utility-system subsidiaries of that holding company have the same designated representative. EPA intends to consider this revision, and other revisions to streamline part 72, in a rulemaking to be completed in 1995.

5. Phase I NO_x Compliance Extensions

Section 76.12 is revised in order to reflect the new low-NO_x-burner-technology definition. The March 22, 1994 rule provides for a Phase I NO_x compliance extension where a tangentially fired boiler was designed and guaranteed, but failed, to meet the presumptive emission limit and there is a contract to install close-coupled or separated overfire air on or before January 1, 1996. The March 22, 1994 rule includes similar language, with regard to wall-fired boilers, providing a Phase I NO_x compliance extension where there is a contract to install additional equipment, including overfire air. 59 FR 13572 (§ 76.12(a)(1) (ii) and (iii)). The direct final rule eliminates these provisions and a related provision in § 76.12(b)(3). No extensions were requested under these provisions.

The March 22, 1994 rule also provides for a Phase I NO_x compliance extension for units where low NO_x burner technology designed to meet the presumptive emission limits is not in adequate supply for installation and operation by January 1, 1995, consistent with system reliability. Requests for the extensions were due by October 1, 1994. These provisions are not changed in the revised rule. Extension requests for 6 units under this provision were submitted, and the requests either have already been granted or will be acted on consistent with the revised rule after its effective date.

The Agency is aware that, in very limited circumstances, an additional extension of the compliance date for Phase I NO_x emission limitations may be warranted. These circumstances are as follows: A source has 3 or more units that have extensions under section 404(d) until January 1, 1997 to comply with Phase I NO_x emission limits and, due to claimed operational problems associated with the planned NO_x emission control systems, one unit may need an additional extension to redesign and install low NO_x burner technology. Because of its extension under section 404(d), the unit has not yet installed the NO_x control system that was designed to comply with the low-NO_x-burner technology definition in the March 22, 1994 rule. With the change adopted today in the definition, the unit has flexibility to redesign the NO_x control system to meet the new definition and avoid the claimed operational problems. However, unless an additional compliance extension is granted, there will be insufficient time to install redesigned low NO_x burner technology without causing system reliability problems.

Because the need for an additional extension appears to result from the change in the low-NO_x-burner-technology definition, the Agency maintains that an additional extension may be appropriate in these limited circumstances. In order to provide the designated representative of the unit an opportunity to demonstrate the need for such extension, the revised rule (in § 76.12(e)) requires the submission of a petition for the extension within 15 days of the publication of the revised rule and establishes procedures for acting on the petition. The procedures and the provisions in the revised rule concerning treatment of the unit upon approval of the petition are essentially the same as the procedures and provisions applicable to Phase I NO_x compliance extensions. See 59 FR 13572–13573 (§ 76.12(c) and (d)).

6. Miscellaneous

The revised rule excludes § 76.9(e) of the March 22, 1994 rule, which provides that each ton of excess emissions of

[11] Consistent with these changes, § 76.11(d)(1)(ii)(B) is revised to state that units must meet either the individual-unit limits "or" the group emission requirement.

NO_X will be a separate violation. In response to the utilities' challenge of § 76.9(e), EPA moved before the Court for a voluntary remand of the provision. The Court granted the motion and therefore EPA is now deleting the provision.

The revised rule also changes provisions concerning the types of units for which reports of cost data on low NO_X burner technology installations must be prepared and the date by which the reports must be submitted under § 76.14(c). Consistent with the new low-NO_X-burner-technology definition, the cost reports are not required for: wall-fired boilers using only overfire air and not low NO_X burners; and tangentially fired boilers using only separated overfire air and not low NO_X burner technology. Because such boilers are not using low NO_X burner technology, cost data on their NO_X emissions controls are not relevant to setting of Group 2, Phase II NO_X emission limitations under section 407(b)(2) of the Act. An analogous change is made in section 1 of appendix B to part 76.

Also excluded from cost reporting are units that begin installing a new NO_X emission control system after 120 days from publication of the instant direct final rule in the **Federal Register**. In light of the statutory requirement that Group 2, Phase II emission limitations be established by January 1, 1997, the Agency maintains that cost information on those units would be received too late to be useful in the rulemaking on such emission limitations.

Finally, the date for submission of cost reports is revised in § 76.14(c)(3) to take account of the vacating of the March 22, 1994 rule by the Court. As in the March 22, 1994 rule, the cost reports must be submitted within 120 days after completion of the low NO_X burner technology retrofit project. However, in order to provide time for resumption and completion of cost data collection that may have been stopped when the rule was vacated, the revised rule ensures that all projects will have at least 40 days, from the publication of the revised rule in the **Federal Register**, to submit the cost reports. Cost reports on projects completed more than 80 days before publication of the direct final rule must be submitted by the 40th day after such publication.

B. Reissuance of the Emission Limits

Section 407(b)(1) requires the Administrator to adopt by regulation the presumptive emission limits unless she finds that they cannot be achieved using low NO_X burner technology. In the March 22, 1994 rule, the Administrator found that the record evidence showed that the presumptive limits were achievable using low NO_X burners plus overfire air for wall-fired boilers and separated overfire air for tangentially fired boilers (59 FR 13546). In light of the revised low-NO_X-burner-technology definition, the Administrator has reviewed the record concerning the performance of low NO_X burners and concludes that the presumptive limits are still achievable. The revised rule therefore reissues the presumptive limits of 0.50 lb/mmBtu for wall-fired boilers and 0.45 lb/mmBtu for tangentially fired boilers.

The record includes analyses conducted by DOE in which the presumptive limits were examined in light of the low-NO_X-burner-technology definition supported by DOE, i.e., the third approach in the November 25, 1992 proposal. The revised rule adopts in essence the same definition as DOE supported. As discussed below, DOE concluded, and the utilities agreed, that most units could achieve the presumptive limits using low NO_X burners without overfire air for wall-fired boilers and without separated overfire air for tangentially fired boilers. See, e.g., Docket Item IV–D–162, Fourth Supplementary Comments of UARG, February 2, 1994 at 16–23.

After reviewing a number of sources of information on control technology efficiency, DOE estimated control technology performance based primarily on data from ongoing demonstration projects and other recent installations of NO_X control systems. The analysis of data from wall-fired and tangentially fired boilers, fitted with low NO_X burner technology as defined by DOE, indicated that NO_X reductions of 45 to 50 percent would be achieved at wall-fired boilers and of 35 to 37 percent would be achieved at tangentially fired boilers (57 FR 55646–55647). DOE's NO_X control technology performance estimates were consistent with average NO_X reductions projected by the utilities. The utilities projected average NO_X reductions of 47 percent with use of burner retrofits for wall-fired boilers and 35 to 37 percent with the use of LNCFS 1 for tangentially fired boilers (Docket Item IV–D–111 at 59–61).[12] Further, the utilities supported DOE's performance estimates in their brief to the Court in *Alabama Power* (Docket Item VIII–A–1, Brief of Petitioners, July 1, 1994, at 18–19).

DOE's analysis also showed that, assuming 45 percent control efficiency for wall-fired boilers and 35 percent for tangentially fired boilers, less than 10 percent of the Group 1 units would fail to meet the presumptive limits (57 FR 55648). Further, the utilities similarly concluded that "review of the uncontrolled emissions at wall-fired and tangentially fired boilers, and of the capabilities of low NO_X burner technology, show that (the presumptive) limits are aggressive but generally achievable by most Group 1 units with the use of (low NO_X burners) alone" (Docket Item IV–D–111 at 138). The utilities reiterated this conclusion before the Court in *Alabama Power*. The utilities stated that "all of the tangentially fired boiler groupings analyzed by EPA's contractor would comply with the final presumptive emission limitation using low NO_X burners alone for tangentially fired boilers (i.e., LNCFS 1), without the use of separated overfire air" (Docket Item VIII–A–1, Brief of Petitioners at 40).

In the March 22, 1994 preamble, EPA did not adopt DOE's analysis and instead presented its own analysis of control technology performance data available after promulgation of the November 25, 1992 proposal. The EPA found that the majority of wall-fired boilers would be expected to achieve NO_X reductions of 40 to 50 percent using low NO_X burners only and no overfire air (59 FR 13546). The EPA also found that tangentially fired boilers using LNCFS 1 would achieve reduction of 20 to 25 percent. While EPA's finding on wall-fired boilers is consistent with DOE's finding, the two analyses differ concerning tangentially fired boilers. However, upon reconsideration, the Agency finds that the 20 to 25 percent estimate of reductions achievable using LNCFS 1 erroneously excluded the reductions using a form of LNCFS 1 referred to in the March 22, 1994 preamble as "LNCFS 1+." 59 FR 13546–13547. Because "LNCFS 1+" (i.e., Lansing Smith Unit 2)[13] employs the

[12] Since the completion of DOE's analysis, other types of low NO_X burner technology have been developed for tangentially fired boilers. See footnote 3 above. Although EPA currently lacks data on the long-term performance of these NO_X controls, the outlook for their performance is promising.

[13] DOE's analysis included Fiddler's Ferry Unit 1 as a unit with LNCFS 1. Since installation of LNCFS 1 in that unit involved major modifications of the existing waterwall holes (i.e., cutting out a waterwall section having a height of 3 feet above each existing waterwall hole and a width equal to the width of the hole), the unit's NO_X control system does not fall within the new low-NO_X-burner technology definition, which includes minor modifications of the existing hole. See Docket Item II–E–11, Record of Telephone Conversations, October 12, 1992. However, eliminating the emission reduction results of that unit does not change the conclusion that LNCFS 1 (e.g., at Lansing Smith Unit 2) can achieve 35 to 37 percent reduction.

same hardware (i.e., air nozzles in the hole with the burner) as LNCFS 1 applications, there is no basis of distinguishing "LNCFS 1+". The differences between EPA's and DOE's data are eliminated by treating "LNCFS 1+" as included in LNCFS 1 and considering the performance results of "LNCFS 1+" as included in results for LNCFS 1.

Upon reconsideration, EPA concurs with the aforementioned DOE and utilities' analyses. EPA, therefore, retains in the revised rule the presumptive limits for Group 1 boilers.

C. Permit Status

Pursuant to the March 22, 1994 rule, the designated representatives of Phase I units with wall-fired or tangentially-fired boilers submitted NO_X compliance plans. (See 59 FR 13567 (§ 76.9 (a) through (c))). For units lacking Acid Rain permits, the NO_X compliance plans were submitted along with applications for such permits. For units that already had Acid Rain permits covering SO_2 emission limitations, the NO_X compliance plans were submitted as permit revisions. Most of the plans required NO_X compliance commencing on January 1, 1995. Twenty-five units had previously been granted 2-year extensions for NO_X compliance under § 72.42, and designated representatives for 6 more units requested 15-month extensions under § 76.12 of the March 22, 1994 rule.

The Agency followed the applicable permit issuance and revision procedures under part 72 of the Acid Rain permits rule. These procedures required notice of a proposed permit or proposed permit revision and opportunity for public comment prior to issuance of a final permit or final revised permit. Most of the submitted NO_X compliance plans were already approved and included in final permits or final revised permits before the November 29, 1994 *Alabama Power* decision vacating the March 22, 1994 rule. Because of the vacating of the rule, the Agency has deferred action on those plans and extension requests that were not yet approved when the Court issued its decision.

Under the March 22, 1994 rule, NO_X compliance plans had to identify which one of several possible compliance options was proposed for each Phase I unit with a Group 1 boiler. *Id.* (§ 76.9(c)(4)). In the NO_X compliance plans already submitted to the Agency, units sought to comply either with the presumptive limits or through NO_X emissions averaging plans. The units that requested NO_X compliance extensions sought to comply either with the presumptive limits or through NO_X emissions averaging plans after the extensions expire.

If, as anticipated, the revised rule becomes final and thereby reinstates the NO_X emission reduction program, the Agency sees no need for utilities to resubmit and for EPA to reissue, through notice and comment procedures, the NO_X compliance plans that have already been approved and issued in final form in permits or permit revisions. The final permits and permit revisions set forth the applicable NO_X emission limitations and do not state any definition for low NO_X burner technology. The revised rule changes the low-NO_X-burner-technology definition but does not change the presumptive limits or the formulas for setting individual-unit limits or showing group compliance in averaging plans. The revised rule preserves without change the provisions governing the Phase I extensions that were requested and either were approved or that would have been approved under the March 22, 1994 rule. The revised rule also does not change the application requirements in § 76.9 or the permit issuance or permit revision procedures in parts 72 and 76 applicable to NO_X compliance plans.

The only changes that the revised rule makes in the submitted NO_X compliance plans are in the general compliance date and in the effect of group compliance on individual-unit limits in NO_X averaging plans. The general deadline for compliance by a Group 1, Phase I unit with NO_X emission limitations is now the later of January 1, 1996 (rather than 1995) or the date on which a unit is subject to SO_2 emission reduction requirements under section 404(d) of the Act. The revised rule also mandates, for all NO_X averaging plans, that where the units in an averaging plan show they meet the group compliance requirement, the units are deemed to meet their individual-unit limits. All NO_X compliance plans must conform to the revised rule.

As discussed above, the Agency has issued, elsewhere in this **Federal Register**, a notice of proposal requesting comments on the provisions of the revised rule. Any comments concerning the compliance deadline and the group compliance provisions should be made in response to that notice and would not be appropriate in the context of permit issuance. All other aspects of the submitted NO_X compliance plans have already been subject to notice and comment and are unchanged by the revised rule.

The Agency concludes that, once the revised rule becomes final as anticipated, conforming changes in the compliance date and group compliance provisions in otherwise unchanged NO_X compliance plans are properly considered administrative amendments under § 72.83 of the Acid Rain permits rule because there is no basis for requiring notice and comment on the changes. All existing permits that include NO_X compliance plans will be amended under § 72.83 to the extent necessary to make them consistent with the new compliance date and group compliance requirements. The administrative amendments will reinstate the NO_X compliance plans as amended and the approved Phase I NO_X compliance extensions under §§ 72.42 and 76.12 that are referenced in the plans.

With regard to NO_X compliance plans in permits or permit revisions issued in draft form for public comment but not yet issued in final form, the Agency will complete the issuance procedure in accordance with the revised rule once the rule becomes final. Since, except for the compliance date and group compliance provisions, neither the substance of such plans nor the issuance procedures were changed by the revised rule, there is no need to reopen the public comment period on the plans.

Any plans that have not yet been issued in draft form will also be processed by the Agency in accordance with the revised rule and part 72. Similarly, any Phase I NO_X compliance extensions requested under § 76.12 and not acted on before November 29, 1994 will be acted on consistent with the revised rule. It should be noted that, if significant, adverse comment is timely received on relevant portions of the instant direct final rule, the NO_X compliance plans could be subject to further change depending on the outcome of the rulemaking initiated by the notice of proposed rule issued elsewhere in this **Federal Register**.

IV. Administrative Requirements

A. 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 Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the

environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a "significant regulatory action" because it will have an annual effect on the economy of approximately $276 million starting in 2000. As such, this action was submitted to OMB for review. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the ADDRESSES section of this preamble.

EPA does not believe a revised Regulatory Impact Analysis (RIA) is needed for the direct final rule, which, in large part, reinstates the March 22, 1994 rule and which imposes no new costs beyond what costs were estimated in the RIA to the March 22, 1994 rule. The EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of U.S. enterprises to compete with foreign enterprises in domestic or foreign markets due to the final rule.

In assessing the impacts of a regulation, it is important to examine: (1) The costs to the regulated community, (2) the costs that are passed on to customers of the regulated community, and (3) the impact of these cost increases on the financial health and competitiveness of both the regulated community and their customers. The costs of this rule to electric utilities are generally very small relative to their annual revenues. (However, the relative amount of the costs will definitely vary in individual cases.) Moreover, EPA expects that most or all utility expenses from meeting NO_X requirements will be passed along to ratepayers. When NO_X requirements are fully implemented in the year 2000, consumer electric utility rates are expected to rise by 0.12 percent on average due to this rulemaking. Consequently, the rule is not likely to have an impact on utility profits or competitiveness.

B. Unfunded Mandates Act

Section 202 of the Unfunded Mandates Reform Act of 1995 ("Unfunded Mandates Act") (signed into law on March 22, 1995) requires that the Agency prepare a budgetary impact statement before promulgating a rule that includes a Federal mandate that may result in expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. The budgetary impact statement must include: (i) Identification of the Federal law under which the rule is promulgated; (ii) a qualitative and quantitative assessment of anticipated costs and benefits of the Federal mandate and an analysis of the extent to which such costs to State, local, and tribal governments may be paid with Federal financial assistance; (iii) if feasible, estimates of the future compliance costs and any disproportionate budgetary effects of the mandate; (iv) if feasible, estimates of the effect on the national economy; and (v) a description of the Agency's prior consultation with elected representatives of State, local, and tribal governments and a summary and evaluation of the comments and concerns presented. Section 203 provides that if any small governments may be significantly or uniquely impacted by the rule, the Agency must establish a plan for obtaining input from and informing, educating, and advising any such potentially affected small governments.

Under section 205 of the Unfunded Mandates Act, the Agency must identify and consider a reasonable number of regulatory alternatives before promulating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the least costly, most cost-effective, or least burdensome alternative, for State, local, and tribal governments and the private sector, that achieves the objectives of the rule, unless the Agency explains why this alternative is not selected or unless the selection of this alternative is inconsistent with law.

Because this direct final rule is estimated to result in the expenditure by State, local, and tribal governments, in aggregate, or the private sector of over $100 million per year starting in 2000, EPA has prepared a supplement to the Regulatory Impact Statement in compliance with the Unfunded Mandates Act. EPA summarizes that supplement as follows.

The direct final rule is promulgated under section 407 of the Clean Air Act. The rule is issued in response to a remand by the U.S. Court of Appeals for the District of Columbia Circuit and, in large part, reinstates the remanded March 22, 1994 rule. Thus, the analysis in the RIA developed in preparation of the March 22, 1994 rule was appropriately considered in response to the requirements of the Unfunded Mandates Act.

Total expenditures resulting from the direct final rule are estimated at: $69 million (of which less than $1 million is by State, local, and tribal governments) per year in 1995–1999; and $276 million (of which $21 million is by State, local, and tribal governments) per year starting in 2000. There are no federal funds available to assist State, local, and tribal governments in meeting these costs. There are important benefits from NO_X emission reductions because atmospheric emissions of NO_X have significant, adverse impacts on human health and welfare and on the environment.

The rule does not have any disproportionate budgetary effects on any particular region of the nation, any State, local, or tribal government, or urban or rural or other type of community. On the contrary, the rule will result in only a minimal increase in average electricity rates. Moreover, the rule will not have a material effect on the national economy.

Prior to issuing the March 22, 1994 rule, EPA provided numerous opportunities, e.g., through the Acid Rain Advisory Committee proceedings, the public comment period, and public hearings, for consultation with interested parties, including State, local, and tribal governments. In general, State and local environmental agencies advocated that EPA adopt more stringent environmental controls while municipally-owned utilities advocated less stringent controls and more compliance flexibility. EPA evaluated the comments and concerns expressed, and the direct final rule reflects, to the extent consistent with section 407 of the Clean Air Act, those comments and concerns. While small governments are not significantly or uniquely affected by the rule, these procedures, as well as additional public conferences and meetings, gave small governments an opportunity to give meaningful and timely input and obtain information, education, and advice on compliance.

The Agency considered several regulatory options in developing the rule. The option selected in the direct final rule is the least costly and least burdensome alternative currently available for achieving the objectives of section 407. The Agency rejected another alternative that was the most cost-effective alternative because the U.S. Court of Appeals for the D.C. Circuit held that the latter alternative was beyond the Agency's statutory authority.

C. Paperwork Reduction Act

The OMB has approved the information collection requirements contained in this rule under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501, *et seq.*, and has assigned OMB control number 2060–0258.

Public reporting burden for this collection of information is estimated at 27,510 hours for all respondents through May 15, 1995. This estimate includes time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

The Agency notes that this burden estimate was originally developed based on the March 22, 1994 rule. Today's direct final rule includes revisions to cost reporting requirements in the March 22, 1994 rule that result in a small reduction in overall burden. In order to account for this small reduction, the Agency will submit an adjustment to the current Information Collection Report.

Send comments regarding this change in the information collection requirements or any other aspect of this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch (PM–223Y), U.S. Environmental Protection Agency, 401 M Street SW., Washington, DC 20460; and to the Paperwork Reduction Project, Office of Information and Regulatory Affairs, Office of Management and Budget, 726 Jackson Place NW., Washington, DC 20503, marked "Attention: Desk Officer for EPA."

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601, *et seq.*) requires EPA to consider potential impacts of proposed regulations on small business "entities." If a preliminary analysis indicates that a proposed regulation would have a significant economic impact on 20 percent or more of small entities, then a regulatory flexibility analysis must be prepared.

Current Regulatory Flexibility Act guidelines indicate that an economic impact should be considered significant if it meets one of the following criteria: (1) Compliance increases annual production costs by more than 5 percent, assuming costs are passed onto consumers; (2) compliance costs as a percentage of sales for small entities are at least 10 percent more than compliance costs as a percentage of sales for large entities; (3) capital costs of compliance represent a "significant" portion of capital available to small entities, considering internal cash flow plus external financial capabilities; or (4) regulatory requirements are likely to result in closures of small entities.

Under the Regulatory Flexibility Act, a small business is any "small business concern" as identified by the Small Business Administration under section 3 of the Small Business Act. As of January 1, 1991, the Small Business Administration had established the size threshold for small electric services companies at 4 million megawatt hours per year. Because all of the utilities affected by Phase I of the Acid Rain regulations have generating capacities greater than 4 million megawatt hours, EPA believes that no small businesses are affected by today's revised rule. The EPA's initial estimates are that the burden on small utilities under Phase II is minimal.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this rule, if promulgated, will not have a significant adverse impact on a substantial number of small entities.

E. Miscellaneous

In accordance with section 117 of the Act, publication of this rule was preceded by consultation with appropriate advisory committees, independent experts, and federal departments and agencies.

List of Subjects in 40 CFR Part 76

Acid rain program, Air pollution control, Nitrogen oxide, Incorporation by reference, Reporting and recordkeeping requirements.

Dated: March 31, 1995.

Carol M. Browner,

Administrator.

Title 40, chapter I, of the Code of Federal Regulations is amended as follows:

1. Part 76 is revised to read as follows:

PART 76—ACID RAIN NITROGEN OXIDES EMISSION REDUCTION PROGRAM

Sec.

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

§ 76.1 Applicability.

(a) Except as provided in paragraphs (b) through (d) of this section, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Act.

(b) The emission limitations for NO_x under this part apply to each affected coal-fired utility unit subject to section 404(d) or 409(b) of the Act on the date the unit is required to meet the Acid Rain emissions reduction requirement for SO_2.

(c) The provisions of this part apply to each coal-fired substitution unit or compensating unit, designated and approved as a Phase I unit pursuant to §§ 72.41 or 72.43 of this chapter as follows:

(1) A coal-fired substitution unit that is designated in a substitution plan that is approved and active as of January 1, 1995 shall be treated as a Phase I coal-fired utility unit for purposes of this part. In the event the designation of such unit as a substitution unit is terminated after December 31, 1995, pursuant to § 72.41 of this chapter and the unit is no longer required to meet Phase I SO_2 emissions limitations, the provisions of this part (including those applicable in Phase I) will continue to apply.

(2) A coal-fired substitution unit that is designated in a substitution plan that is not approved or not active as of January 1, 1995, or a coal-fired compensating unit, shall be treated as a Phase II coal-fired utility unit for purposes of this part.

(d) The provisions of this part for Phase I units apply to each coal-fired transfer unit governed by a Phase I extension plan, approved pursuant to

§ 72.42 of this chapter, on January 1, 1997. Notwithstanding the preceding sentence, a coal-fired transfer unit shall be subject to the Acid Rain emissions limitations for nitrogen oxides beginning on January 1, 1996 if, for that year, a transfer unit is allocated fewer Phase I extension reserve allowances than the maximum amount that the designated representative could have requested in accordance with § 72.42(c)(5) of this chapter (as adjusted under § 72.42(d) of this chapter) unless the transfer unit is the last unit allocated Phase I extension reserve allowances under the plan.

§ 76.2 Definitions.

All terms used in this part shall have the meaning set forth in the Act, in § 72.2 of this chapter, and in this section as follows:

Alternative contemporaneous annual emission limitation means the maximum allowable NO_X emission rate (on a lb/mmBtu, annual average basis) assigned to an individual unit in a NO_X emissions averaging plan pursuant to § 76.10.

Alternative technology means a control technology for reducing NO_X emissions that is outside the scope of the definition of low NO_X burner technology. Alternative technology does not include overfire air as applied to wall-fired boilers or separated overfire air as applied to tangentially fired boilers.

Approved clean coal technology demonstration project means a project using funds appropriated under the Department of Energy's "Clean Coal Technology Demonstration Program," up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency. The Federal contribution for a qualifying project shall be at least 20 percent of the total cost of the demonstration project.

Cell burner boiler means a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Any low NO_X retrofit of a cell burner boiler that reuses the existing cell burner, close-coupled wall opening configuration would not change the designation of the unit as a cell burner boiler.

Coal-fired utility unit means a utility unit in which the combustion of coal (or any coal-derived fuel) on a Btu basis exceeds 50.0 percent of its annual heat input, for Phase I units in calendar year 1990 and, for Phase II units in the calendar year 1995. For the purposes of this part, this definition shall apply notwithstanding the definition at § 72.2 of this chapter.

Cyclone boiler means a boiler with one or more water-cooled horizontal cylindrical chambers in which coal combustion takes place. The horizontal cylindrical chamber(s) is (are) attached to the bottom of the furnace. One or more cylindrical chambers are arranged either on one furnace wall or on two opposed furnace walls. Gaseous combustion products exiting from the chamber(s) turn 90 degrees to go up through the boiler while coal ash exits the bottom of the boiler as a molten slag.

Demonstration period means a period of time not less than 15 months, approved under § 76.10, for demonstrating that the affected unit cannot meet the applicable emission limitation under §§ 76.5, 76.6, or 76.7 and establishing the minimum NO_X emission rate that the unit can achieve during long-term load dispatch operation.

Dry bottom means the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid.

Economizer means the lowest temperature heat exchange section of a utility boiler where boiler feed water is heated by the flue gas.

Flue gas means the combustion products arising from the combustion of fossil fuel in a utility boiler.

Group 1 boiler means a tangentially fired boiler or a dry bottom wall-fired boiler (other than a unit applying cell burner technology).

Group 2 boiler means a wet bottom wall-fired boiler, a cyclone boiler, a boiler applying cell burner technology, a vertically fired boiler, an arch-fired boiler, or any other type of utility boiler (such as a fluidized bed or stoker boiler) that is not a Group 1 boiler.

Low NO_X burners and *low NO_X burner technology* means commercially available combustion modification NO_X controls that minimize NO_X formation by introducing coal and its associated combustion air into a boiler such that initial combustion occurs in a manner that promotes rapid coal devolatilization in a fuel-rich (i.e., oxygen deficient) environment and introduces additional air to achieve a final fuel-lean (i.e., oxygen rich) environment to complete the combustion process. This definition shall include the staging of any portion of the combustion air using air nozzles or registers located inside any waterwall hole that includes a burner. This definition shall exclude the staging of any portion of the combustion air using air nozzles or ports located outside any waterwall hole that includes a burner (commonly referred to as NO_X ports or separated overfire air ports).

Operating period means a period of time of not less than three consecutive months and that occurs not more than one month prior to applying for an alternative emission limitation demonstration period under § 76.10, during which the owner or operator of an affected unit that cannot meet the applicable emission limitation:

(1) Operates the installed NO_X emission controls in accordance with primary vendor specifications and procedures, with the unit operating under normal conditions; and

(2) records and reports quality-assured continuous emission monitoring (CEM) and unit operating data according to the methods and procedures in part 75 of this chapter.

Primary vendor means the vendor of the NO_X emission control system who has primary responsibility for providing the equipment, service, and technical expertise necessary for detailed design, installation, and operation of the controls, including process data, mechanical drawings, operating manuals, or any combination thereof.

Reburning means reducing the coal and combustion air to the main burners and injecting a reburn fuel (such as gas or oil) to create a fuel-rich secondary combustion zone above the main burner zone and final combustion air to create a fuel-lean burnout zone. The formation of NO_X is inhibited in the main burner zone due to the reduced combustion intensity, and NO_X is destroyed in the fuel-rich secondary combustion zone by conversion to molecular nitrogen.

Selective catalytic reduction means a noncombustion control technology that destroys NO_X by injecting a reducing agent (e.g., ammonia) into the flue gas that, in the presence of a catalyst (e.g., vanadium, titanium, or zeolite), converts NO_X into molecular nitrogen and water.

Selective noncatalytic reduction means a noncombustion control technology that destroys NO_X by injecting a reducing agent (e.g., ammonia, urea, or cyanuric acid) into the flue gas, downstream of the combustion zone that converts NO_X to molecular nitrogen, water, and when urea or cyanuric acid are used, to carbon dioxide (CO_2).

Stoker boiler means a boiler that burns solid fuel in a bed, on a stationary or moving grate, that is located at the bottom of the furnace.

Tangentially fired boiler means a boiler that has coal and air nozzles mounted in each corner of the furnace where the vertical furnace walls meet. Both pulverized coal and air are directed from the furnace corners along a line tangential to a circle lying in a horizontal plane of the furnace.

Turbo-fired boiler means a pulverized coal, wall-fired boiler with burners arranged on walls so that the individual flames extend down toward the furnace bottom and then turn back up through the center of the furnace.

Wall-fired boiler means a boiler that has pulverized coal burners arranged on the walls of the furnace. The burners have discrete, individual flames that extend perpendicularly into the furnace area.

Wet bottom means the boiler has a furnace bottom temperature above the ash melting point and the bottom ash is removed as a liquid.

§ 76.3 General Acid Rain Program provisions.

The following provisions of part 72 of this chapter shall apply to this part:

(a) § 72.2 (Definitions);
(b) § 72.3 (Measurements, abbreviations, and acronyms);
(c) § 72.4 (Federal authority);
(d) § 72.5 (State authority);
(e) § 72.6 (Applicability);
(f) § 72.7 (New unit exemption);
(g) § 72.8 (Retired units exemption);
(h) § 72.9 (Standard requirements);
(i) § 72.10 (Availability of information); and
(j) § 72.11 (Computation of time).

In addition, the procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

§ 76.4 Incorporation by reference.

(a) The materials listed in this section are incorporated by reference in the sections noted. These incorporations by reference (IBR's) were approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they existed on the date of approval, and notice of any change in these materials will be published in the **Federal Register**. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, 800 North Capitol St., NW., 7th Floor, Suite 700, Washington, DC, at the Public Information Reference Unit, U.S. EPA, 401 M Street, SW., Washington, DC, and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; or the University Microfilms International, 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D 3176–89, Standard Practice for Ultimate Analysis of Coal and Coke, IBR approved May 23, 1995 for § 76.15.

(2) ASTM D 3172–89, Standard Practice for Proximate Analysis of Coal and Coke, IBR approved May 23, 1995 for § 76.15.

(c) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), 22 Law Drive, Box 2350, Fairfield, NJ 07007–2350.

(1) ASME Performance Test Code 4.2 (1991), Test Code for Coal Pulverizers, IBR approved May 23, 1995 for § 76.15.

(2) [Reserved]

(d) The following material is available for purchase from the American National Standards Institute, 11 West 42nd Street, New York, NY 10036 or from the International Organization for Standardization (ISO), Case Postale 56, CH–1211 Geneve 20, Switzerland.

(1) ISO 9931 (December, 1991) "Coal—Sampling of Pulverized Coal Conveyed by Gases in Direct Fired Coal Systems," IBR approved May 23, 1995 for § 76.15.

(2) [Reserved]

§ 76.5 NO_X emission limitations for Group 1 boilers.

(a) Beginning January 1, 1996, or for a unit subject to section 404(d) of the Act, the date on which the unit is required to meet Acid Rain emission reduction requirements for SO_2, the owner or operator of a Phase I coal-fired utility unit with a tangentially fired boiler or a dry bottom wall-fired boiler (other than units applying cell burner technology) shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere in excess of the following limits, except as provided in paragraphs (c) or (e) of this section or in §§ 76.10, 76.11, or 76.12:

(1) 0.45 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.50 lb/mmBtu of heat input on an annual average basis for dry bottom wall-fired boilers (other than units applying cell burner technology).

(b) The owner or operator shall determine the annual average NO_X emission rate, in lb/mmBtu, using the methods and procedures specified in part 75 of this chapter.

(c) Unless the unit meets the early election requirement of § 76.8, the owner or operator of a coal-fired substitution unit with a tangentially fired boiler or a dry bottom wall-fired boiler (other than units applying cell burner technology) that satisfies the requirements of § 76.1(c)(2), shall comply with the NO_X emission limitations that apply to Group 1, Phase II boilers.

(d) The owner or operator of a Phase I unit with a cell burner boiler that converts to a conventional wall-fired boiler on or before January 1, 1995 or, for a unit subject to section 404(d) of the Act, the date the unit is required to meet Acid Rain emissions reduction requirements for SO_2 shall comply, by such respective date or January 1, 1996, whichever is later, with the NO_X emissions limitation applicable to dry bottom wall-fired boilers under paragraph (a) of this section, except as provided in paragraphs (c) or (e) of this section or in §§ 76.10, 76.11, or 76.12.

(e) The owner or operator of a Phase I unit with a Group 1 boiler that converts to a fluidized bed or other type of utility boiler not included in Group 1 boilers on or before January 1, 1995 or, for a unit subject to section 404(d) of the Act, the date the unit is required to meet Acid Rain emissions reduction requirements for SO_2 is exempt from the NO_X emissions limitations specified in paragraph (a) of this section, but shall comply with the NO_X emission limitations for Group 2 boilers under § 76.6.

(f) Except as provided in § 76.8 and in paragraph (c) of this section, each unit subject to the requirements of this section is not subject to the requirements of § 76.7.

(g) Beginning January 1, 2000, the owner or operator of a Group 1, Phase II coal-fired utility unit with a tangentially fired boiler or a wall-fired boiler shall be subject to the emission limitations in paragraph (a) of this section.

§ 76.6 NO_X emission limitations for Group 2 boilers. [Reserved]

§ 76.7 Revised NO_X emission limitations for Group 1, Phase II boilers. [Reserved]

§ 76.8 Early election for Group 1, Phase II boilers.

(a) *General provisions.* (1) The owner or operator of a Phase II coal-fired utility unit with a Group 1 boiler may elect to have the unit become subject to the applicable emissions limitation for NO_X under § 76.5, starting no later than January 1, 1997.

(2) The owner or operator of a Phase II coal-fired utility unit with a Group 1 boiler that elects to become subject to the applicable emission limitation under § 76.5 shall not be subject to any revised NO_X emissions limitation for Group 1 boilers that the Administrator may issue pursuant to section 407(b)(2) of the Act until January 1, 2008,

provided the designated representative demonstrates that the unit is in compliance with the limitation under § 76.5, using the methods and procedures specified in part 75 of this chapter, for the period beginning January 1 of the year in which the early election takes effect (but not later than January 1, 1997) and ending December 31, 2007.

(3) The owner or operator of any Phase II unit with a cell burner boiler that converts to conventional burner technology may elect to become subject to the applicable emissions limitation under § 76.5 for dry bottom wall-fired boilers, provided the owner or operator complies with the provisions in paragraph (a)(2) of this section.

(4) The owner or operator of a Phase II unit approved for early election shall not submit an application for an alternative emissions limitation demonstration period under § 76.10 until the earlier of:

(i) January 1, 2008; or

(ii) Early election is terminated pursuant to paragraph (e)(3) of this section.

(5) The owner or operator of a Phase II unit approved for early election may not incorporate the unit into an averaging plan prior to January 1, 2000. On or after January 1, 2000, for purposes of the averaging plan, the early election unit will be treated as subject to the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under §§ 76.5(g) and if revised emission limitations are issued for Group 1 boilers pursuant to section 407(b)(2) of the Act, § 76.7.

(b) *Submission requirements.* In order to obtain early election status, the designated representative of a Phase II unit with a Group 1 boiler shall submit an early election plan to the Administrator by January 1 of the year the early election is to take effect, but not later than January 1, 1997. Notwithstanding § 72.40 of this chapter, and unless the unit is a substitution unit under § 72.41 of this chapter or a compensating unit under § 72.43 of this chapter, a complete compliance plan covering the unit shall not include the provisions for SO_2 emissions under § 72.40(a)(1) of this chapter.

(c) *Contents of an early election plan.* A complete early election plan shall include the following elements in a format prescribed by the Administrator:

(1) A request for early election;

(2) The first year for which early election is to take effect, but not later than 1997; and

(3) The special provisions under paragraph (e) of this section.

(d)(1) *Permitting authority's action.* To the extent the Administrator determines that an early election plan complies with the requirements of this section, the Administrator will approve the plan and:

(i) If a Phase I Acid Rain permit governing the source at which the unit is located has been issued, will revise the permit in accordance with the permit modification procedures in § 72.81 of this chapter to include the early election plan; or

(ii) If a Phase I Acid Rain permit governing the source at which the unit is located has not been issued, will issue a Phase I Acid Rain permit effective from January 1, 1995 through December 31, 1999, that will include the early election plan and a complete compliance plan under § 72.40(a) of this chapter and paragraph (b) of this section. If the early election plan is not effective until after January 1, 1995, the permit will not contain any NO_X emissions limitations until the effective date of the plan.

(2) Beginning January 1, 2000, the permitting authority will approve any early election plan previously approved by the Administrator during Phase I, unless the plan is terminated pursuant to paragraph (e)(3) of this section.

(e) *Special provisions*—(1) *Emissions limitations.*—(i) *Sulfur dioxide.* Notwithstanding § 72.9 of this chapter, a unit that is governed by an approved early election plan and that is not a substitution unit under § 72.41 of this chapter or a compensating unit under § 72.43 of this chapter shall not be subject to the following standard requirements under § 72.9 of this chapter for Phase I:

(A) The permit requirements under §§ 72.9(a)(1) (i) and (ii) of this chapter;

(B) The sulfur dioxide requirements under § 72.9(c) of this chapter; and

(C) The excess emissions requirements under § 72.9(e)(1) of this chapter.

(ii) *Nitrogen oxides.* A unit that is governed by an approved early election plan shall be subject to an emissions limitation for NO_X as provided under paragraph (a)(2) of this section except as provided under paragraph (e)(3)(iii) of this section.

(2) *Liability.* The owners and operators of any unit governed by an approved early election plan shall be liable for any violation of the plan or this section at that unit. The owners and operators shall be liable, beginning January 1, 2000, for fulfilling the obligations specified in part 77 of this chapter.

(3) *Termination.* An approved early election plan shall be in effect only until the earlier of January 1, 2008 or January 1 of the calendar year for which a termination of the plan takes effect.

(i) If the designated representative of the unit under an approved early election plan fails to demonstrate compliance with the applicable emissions limitation under § 76.5 for any year during the period beginning January 1 of the first year the early election takes effect and ending December 31, 2007, the permitting authority will terminate the plan. The termination will take effect beginning January 1 of the year after the year for which there is a failure to demonstrate compliance, and the designated representative may not submit a new early election plan.

(ii) The designated representative of the unit under an approved early election plan may terminate the plan any year prior to 2008 but may not submit a new early election plan. In order to terminate the plan, the designated representative must submit a notice under § 72.40(d) of this chapter by January 1 of the year for which the termination is to take effect.

(iii)(A) If an early election plan is terminated any year prior to 2000, the unit shall meet, beginning January 1, 2000, the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under § 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act, § 76.7.

(B) If an early election plan is terminated in or after 2000, the unit shall meet, beginning on the effective date of the termination, the applicable emissions limitation for NO_X for Phase II units with Group 1 boilers under § 76.5(g) and, if revised emission limitations are issued pursuant to section 407(b)(2) of the Act, § 76.7.

§ 76.9 Permit application and compliance plans.

(a) *Duty to apply.* (1) The designated representative of any source with an affected unit subject to this part shall submit, by the applicable deadline under paragraph (b) of this section, a complete Acid Rain permit application (or, if the unit is covered by an Acid Rain permit, a complete permit revision) that includes a complete compliance plan for NO_X emissions covering the unit.

(2) The original and three copies of the permit application and compliance plan for NO_X emissions for Phase I shall be submitted to the EPA regional office for the region where the applicable source is located. The original and three copies of the permit application and compliance plan for NO_X emissions for

Phase II shall be submitted to the permitting authority.

(b) *Deadlines.* (1) For a Phase I unit with a Group 1 boiler, the designated representative shall submit a complete permit application and compliance plan for NO_X covering the unit during Phase I to the applicable permitting authority not later than May 6, 1994.

(2) For a Phase I or Phase II unit with a Group 2 boiler or a Phase II unit with a Group 1 boiler, the designated representative shall submit a complete permit application and compliance plan for NO_X emissions covering the unit in Phase II to the Administrator not later than January 1, 1998, except that early election units shall also submit an application not later than January 1, 1997.

(c) *Information requirements for NO_X compliance plans.* (1) In accordance with § 72.40(a)(2) of this chapter, a complete compliance plan for NO_X shall, for each affected unit included in the permit application and subject to this part, either certify that the unit will comply with the applicable emissions limitation under § 76.5, 76.6, or 76.7 or specify one or more other Acid Rain compliance options for NO_X in accordance with the requirements of this part. A complete compliance plan for NO_X for a source shall include the following elements in a format prescribed by the Administrator:

(i) Identification of the source;

(ii) Identification of each affected unit that is at the source and is subject to this part;

(iii) Identification of the boiler type of each unit;

(iv) Identification of the compliance option proposed for each unit (i.e., meeting the applicable emissions limitation under §§ 76.5, 76.6, 76.7, 76.8 (early election), 76.10 (alternative emission limitation), 76.11 (NO_X emissions averaging), or 76.12 (Phase I NO_X compliance extension)) and any additional information required for the appropriate option in accordance with this part;

(v) Reference to the standard requirements in § 72.9 of this chapter (consistent with § 76.8(e)(1)(i)); and

(vi) The requirements of §§ 72.21 (a) and (b) of this chapter.

(d) *Duty to reapply.* The designated representative of any source with an affected unit subject to this part shall submit a complete Acid Rain permit application, including a complete compliance plan for NO_X emissions covering the unit, in accordance with the deadlines in § 72.30(c) of this chapter.

§ 76.10 Alternative emission limitations.

(a) *General provisions.* (1) The designated representative of an affected unit that is not an early election unit pursuant to § 76.8 and cannot meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 using, for Group 1 boilers, either low NO_X burner technology or an alternative technology in accordance with paragraph (e)(11) of this section, or, for tangentially fired boilers, separated overfire air, or, for Group 2 boilers, the technology on which the applicable emission limitation is based may petition the permitting authority for an alternative emission limitation less stringent than the applicable emission limitation.

(2) In order for the unit to qualify for an alternative emission limitation, the designated representative shall demonstrate that the affected unit cannot meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 based on a showing, to the satisfaction of the Administrator, that:

(i) (A) For a tangentially fired boiler, the owner or operator has either properly installed low NO_X burner technology or properly installed separated overfire air; or

(B) For a dry bottom wall-fired boiler (other than a unit applying cell burner technology), the owner or operator has properly installed low NO_X burner technology; or

(C) For a Group 1 boiler, the owner or operator has properly installed an alternative technology (including but not limited to reburning, selective noncatalytic reduction, or selective catalytic reduction) that achieves NO_X emission reductions demonstrated in accordance with paragraph (e)(11) of this section; or

(D) For a Group 2 boiler, the owner or operator has properly installed the appropriate NO_X emission control technology on which the applicable emission limitation in § 76.6 is based; and

(ii) The installed NO_X emission control system has been designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7; and

(iii) For a demonstration period of at least 15 months or other period of time, as provided in paragraph (f)(1) of this section:

(A) The NO_X emission control system has been properly installed and properly operated according to specifications and procedures designed to minimize the emissions of NO_X to the atmosphere;

(B) Unit operating data as specified in this section show that the unit and NO_X emission control system were operated in accordance with the bid and design specifications on which the design of the NO_X emission control system was based; and

(C) Unit operating data as specified in this section, continuous emission monitoring data obtained pursuant to part 75 of this chapter, and the test data specific to the NO_X emission control system show that the unit could not meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7.

(b) *Petitioning process.* The petitioning process for an alternative emission limitation shall consist of the following steps:

(1) Operation during a period of at least 3 months, following the installation of the NO_X emission control system, that shows that the specific unit and the NO_X emission control system was unable to meet the applicable emissions limitation under §§ 76.5, 76.6, or 76.7 and was operated in accordance with the operating conditions upon which the design of the NO_X emission control system was based and with vendor specifications and procedures;

(2) Submission of a petition for an alternative emission limitation demonstration period as specified in paragraph (d) of this section;

(3) Operation during a demonstration period of at least 15 months, or other period of time as provided in paragraph (f)(1) of this section, that demonstrates the inability of the specific unit to meet the applicable emissions limitation under §§ 76.5, 76.6, or 76.7 and the minimum NO_X emissions rate that the specific unit can achieve during long-term load dispatch operation; and

(4) Submission of a petition for a final alternative emission limitation as specified in paragraph (e) of this section.

(c) *Deadlines.*—(1) *Petition for an alternative emission limitation demonstration period.* The designated representative of the unit shall submit a petition for an alternative emission limitation demonstration period to the permitting authority after the unit has been operated for at least 3 months after installation of the NO_X emission control system required under paragraph (a)(2) of this section and by the following deadline:

(i) For units that seek to have an alternative emission limitation demonstration period apply during all or part of calendar year 1996, or any previous calendar year by the later of:

(A) 120 days after startup of the NO_X emission control system, or

(B) May 1, 1996.

(ii) For units that seek an alternative emission limitation demonstration period beginning in a calendar year after 1996, not later than:

(A) 120 days after January 1 of that calendar year, or

(B) 120 days after startup of the NO_X emission control system if the unit is not operating at the beginning of that calendar year.

(2) *Petition for a final alternative emission limitation.* Not later than 90 days after the end of an approved alternative emission limitation demonstration period for the unit, the designated representative of the unit may submit a petition for an alternative emission limitation to the permitting authority.

(3) *Renewal of an alternative emission limitation.* In order to request continuation of an alternative emission limitation, the designated representative must submit a petition to renew the alternative emission limitation on the date that the application for renewal of the source's Acid Rain permit containing the alternative emission limitation is due.

(d) *Contents of petition for an alternative emission limitation demonstration period.* The designated representative of an affected unit that has met the minimum criteria under paragraph (a) of this section and that has been operated for a period of at least 3 months following the installation of the required NO_X emission control system may submit to the permitting authority a petition for an alternative emission limitation demonstration period. In the petition, the designated representative shall provide the following information in a format prescribed by the Administrator:

(1) Identification of the unit;

(2) The type of NO_X control technology installed (e.g., low NO_X burner technology, selective noncatalytic reduction, selective catalytic reduction, reburning);

(3) If an alternative technology is installed, the time period (not less than 6 consecutive months) prior to installation of the technology to be used for the demonstration required in paragraph (e)(11) of this section.

(4) Documentation as set forth in § 76.14(a)(1) showing that the installed NO_X emission control system has been designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 and that the system has been properly installed according to procedures and specifications designed to minimize the emissions of NO_X to the atmosphere;

(5) The date the unit commenced operation following the installation of the NO_X emission control system or the date the specific unit became subject to the emission limitations of §§ 76.5, 76.6, or 76.7, whichever is later;

(6) The dates of the operating period (which must be at least 3 months long);

(7) Certification by the designated representative that the owner(s) or operator operated the unit and the NO_X emission control system during the operating period in accordance with: Specifications and procedures designed to achieve the maximum NO_X reduction possible with the installed NO_X emission control system or the applicable emission limitation in §§ 76.5, 76.6, or 76.7; the operating conditions upon which the design of the NO_X emission control system was based; and vendor specifications and procedures;

(8) A brief statement describing the reason or reasons why the unit cannot achieve the applicable emission limitation in §§ 76.5, 76.6, or 76.7;

(9) A demonstration period plan, as set forth in § 76.14(a)(2);

(10) Unit operating data and quality-assured continuous emission monitoring data (including the specific data items listed in § 76.14(a)(3) collected in accordance with part 75 of this chapter during the operating period) and demonstrating the inability of the specific unit to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis while operating as certified under paragraph (d)(7) of this section;

(11) An interim alternative emission limitation, in lb/mmBtu, that the unit can achieve during a demonstration period of at least 15 months. The interim alternative emission limitation shall be derived from the data specified in paragraph (d)(10) of this section using methods and procedures satisfactory to the Administrator;

(12) The proposed dates of the demonstration period (which must be at least 15 months long);

(13) A report which outlines the testing and procedures to be taken during the demonstration period in order to determine the maximum NO_X emission reduction obtainable with the installed system. The report shall include the reasons for the NO_X emission control system's failure to meet the applicable emission limitation, and the tests and procedures that will be followed to optimize the NO_X emission control system's performance. Such tests and procedures may include those identified in § 76.15 as appropriate.

(14) The special provisions at paragraph (g)(1) of this section.

(e) *Contents of petition for a final alternative emission limitation.* After the approved demonstration period, the designated representative of the unit may petition the permitting authority for an alternative emission limitation. The petition shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit;

(2) Certification that the owner(s) or operator operated the affected unit and the NO_X emission control system during the demonstration period in accordance with: specifications and procedures designed to achieve the maximum NO_X reduction possible with the installed NO_X emission control system or the applicable emissions limitation in §§ 76.5, 76.6, or 76.7; the operating conditions (including load dispatch conditions) upon which the design of the NO_X emission control system was based; and vendor specifications and procedures.

(3) Certification that the owner(s) or operator have installed in the affected unit all NO_X emission control systems, made any operational modifications, and completed any planned upgrades and/or maintenance to equipment specified in the approved demonstration period plan for optimizing NO_X emission reduction performance, consistent with the demonstration period plan and the proper operation of the installed NO_X emission control system. Such certification shall explain any differences between the installed NO_X emission control system and the equipment configuration described in the approved demonstration period plan.

(4) A clear description of each step or modification taken during the demonstration period to improve or optimize the performance of the installed NO_X emission control system.

(5) Engineering design calculations and drawings that show the technical specifications for installation of any additional operational or emission control modifications installed during the demonstration period.

(6) Unit operating and quality-assured continuous emission monitoring data (including the specific data listed in § 76.14(b)) collected in accordance with part 75 of this chapter during the demonstration period and demonstrating the inability of the specific unit to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis while operating in accordance with the certification under paragraph (e)(2) of this section.

(7) A report (based on the parametric test requirements set forth in the approved demonstration period plan as identified in paragraph (d)(13) of this section), that demonstrates the unit was operated in accordance with the operating conditions upon which the

design of the NO_X emission control system was based and describes the reason or reasons for the failure of the installed NO_X emission control system to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis.

(8) The minimum NO_X emission rate, in lb/mmBtu, that the affected unit can achieve on an annual average basis with the installed NO_X emission control system. This value, which shall be the requested alternative emission limitation, shall be derived from the data specified in this section using methods and procedures satisfactory to the Administrator and shall be the lowest annual emission rate the unit can achieve with the installed NO_X emission control system;

(9) All supporting data and calculations documenting the determination of the requested alternative emission limitation and its conformance with the methods and procedures satisfactory to the Administrator;

(10) The special provisions in paragraph (g)(2) of this section.

(11) In addition to the other requirements of this section, the owner or operator of an affected unit with a Group 1 boiler that has installed an alternative technology in addition to or in lieu of low NO_X burner technology and cannot meet the applicable emission limitation in § 76.5 shall demonstrate, to the satisfaction of the Administrator, that the actual percentage reduction in NO_X emissions (lbs/mmBtu), on an annual average basis is greater than 65 percent of the average annual NO_X emissions prior to the installation of the NO_X emission control system. The percentage reduction in NO_X emissions shall be determined using continuous emissions monitoring data for NO_X taken during the time period (under paragraph (d)(3) of this section) prior to the installation of the NO_X emission control system and during long-term load dispatch operation of the specific boiler.

(f) *Permitting authority's action.—(1) Alternative emission limitation demonstration period.* (i) The permitting authority may approve an alternative emission limitation demonstration period and demonstration period plan, provided that the requirements of this section are met to the satisfaction of the permitting authority. The permitting authority shall disapprove a demonstration period if the requirements of paragraph (a) of this section were not met during the operating period.

(ii) If the demonstration period is approved, the permitting authority will include, as part of the demonstration period, the 4 month period prior to submission of the application in the demonstration period.

(iii) The alternative emission limitation demonstration period will authorize the unit to emit at a rate not greater than the interim alternative emission limitation during the demonstration period on or after January 1, 1996 for Phase I units and the applicable date established in §§ 76.5(g) or 76.6 for Phase II units, and until the date that the Administrator approves or denies a final alternative emission limitation.

(iv) After an alternative emission limitation demonstration period is approved, if the designated representative requests an extension of the demonstration period in accordance with paragraph (g)(1)(i)(B) of this section, the permitting authority may extend the demonstration period by administrative amendment (under § 72.83 of this chapter) to the Acid Rain permit.

(v) The permitting authority shall deny the demonstration period if the designated representative cannot demonstrate that the unit met the requirements of paragraph (a)(2) of this section. In such cases, the permitting authority shall require that the owner or operator operate the unit in compliance with the applicable emission limitation in §§ 76.5, 76.6, or 76.7 for the period preceding the submission of the application for an alternative emission limitation demonstration period, including the operating period, if such periods are after the date on which the unit is subject to the standard limit under §§ 76.5, 76.6, or 76.7.

(2) *Alternative emission limitation.* (i) If the permitting authority determines that the requirements in this section are met, the permitting authority will approve an alternative emission limitation and issue or revise an Acid Rain permit to apply the approved limitation, in accordance with subparts F and G of part 72 of this chapter. The permit will authorize the unit to emit at a rate not greater than the approved alternative emission limitation, starting the date the permitting authority revises an Acid Rain permit to approve an alternative emission limitation.

(ii) If a permitting authority disapproves an alternative emission limitation under paragraph (a)(2) of this section, the owner or operator shall operate the affected unit in compliance with the applicable emission limitation in §§ 76.5, 76.6, or 76.7 (unless the unit is participating in an approved averaging plan under § 76.11) beginning on the date the permitting authority revises an Acid Rain permit to disapprove an alternative emission limitation.

(3) *Alternative emission limitation renewal.* (i) If, upon review of a petition to renew an approved alternative emission limitation, the permitting authority determines that no changes have been made to the control technology, its operation, the operating conditions on which the alternative emission limitation was based, or the actual NO_X emission rate, the alternative emission limitation will be renewed.

(ii) If the permitting authority determines that changes have been made to the control technology, its operation, the fuel quality, or the operating conditions on which the alternative emission limitation was based, the designated representative shall submit, in order to renew the alternative emission limitation or to obtain a new alternative emission limitation, a petition for an alternative emission limitation demonstration period that meets the requirements of paragraph (d) of this section using a new demonstration period.

(g) *Special provisions.*—(1) *Alternative emission limitation demonstration period.* (i) *Emission limitations.* (A) Each unit with an approved alternative emission limitation demonstration period shall comply with the interim emission limitation specified in the unit's permit beginning on the effective date of the demonstration period specified in the permit and, if a timely petition for a final alternative emission limitation is submitted, extending until the date on which the permitting authority issues or revises an Acid Rain permit to approve or disapprove an alternative emission limitation. If a timely petition is not submitted, then the unit shall comply with the standard emission limit under §§ 76.5, 76.6, or 76.7 beginning on the date the petition was required to be submitted under paragraph (c)(2) of this section.

(B) When the owner or operator identifies, during the demonstration period, boiler operating or NO_X emission control system modifications or upgrades that would produce further NO_X emission reductions, enabling the affected unit to comply with or bring its emission rate closer to the applicable emissions limitation under §§ 76.5, 76.6, or 76.7, the designated representative may submit a request and the permitting authority may grant, by administrative amendment under § 72.83 of this chapter, an extension of the demonstration period for such period of time (not to exceed 12 months) as may be necessary to implement such modifications or upgrades.

(C) If the approved interim alternative emission limitation applies to a unit for part, but not all, of a calendar year, the unit shall determine compliance for the calendar year in accordance with the procedures in § 76.13(a).

(ii) *Operating requirements.* (A) A unit with an approved alternative emission limitation demonstration period shall be operated under load dispatch conditions consistent with the operating conditions upon which the design of the NO_X emission control system and performance guarantee were based, and in accordance with the demonstration period plan.

(B) A unit with an approved alternative emission limitation demonstration period shall install all NO_X emission control systems, make any operational modifications, and complete any upgrades and maintenance to equipment specified in the approved demonstration period plan for optimizing NO_X emission reduction performance.

(C) When the owner or operator identifies boiler or NO_X emission control system operating modifications that would produce higher NO_X emission reductions, enabling the affected unit to comply with, or bring its emission rate closer to, the applicable emission limitation under §§ 76.5, 76.6, or 76.7, the designated representative shall submit an administrative amendment under § 72.83 of this chapter to revise the unit's Acid Rain permit and demonstration period plan to include such modifications.

(iii) *Testing requirements.* A unit with an approved alternative emission limitation demonstration period shall monitor in accordance with part 75 of this chapter and shall conduct all tests required under the approved demonstration period plan.

(2) *Final alternative emission limitation.*—(i) *Emission limitations.* (A) Each unit with an approved alternative emission limitation shall comply with the alternative emission limitation specified in the unit's permit beginning on the date specified in the permit as issued or revised by the permitting authority to apply the final alternative emission limitation.

(B) If the approved interim or final alternative emission limitation applies to a unit for part, but not all, of a calendar year, the unit shall determine compliance for the calendar year in accordance with the procedures in § 76.13(a).

§ 76.11 Emissions averaging.

(a) *General provisions.* In lieu of complying with the applicable emission limitation in §§ 76.5, 76.6, or 76.7, any affected units subject to such emission limitation, under control of the same owner or operator, and having the same designated representative may average their NO_X emissions under an averaging plan approved under this section.

(1) Each affected unit included in an averaging plan for Phase I shall be a Phase I unit with a Group 1 boiler subject to an emission limitation in § 76.5 during all years for which the unit is included in the plan.

(i) If a unit with an approved NO_X compliance extension is included in an averaging plan for 1996, the unit shall be treated, for the purposes of applying Equation 1 in paragraph (a)(6) of this section and Equation 2 in paragraph (d)(1)(ii)(A) of this section, as subject to the applicable emissions limitation under § 76.5 for the entire year 1996.

(ii) A Phase II unit approved for early election under § 76.8 shall not be included in an averaging plan for Phase I.

(2) Each affected unit included in an averaging plan for Phase II shall be a boiler subject to an emission limitation in §§ 76.5, 76.6, or 76.7 for all years for which the unit is included in the plan.

(3) Each unit included in an averaging plan shall have an alternative contemporaneous annual emission limitation (lb/mmBtu) and can only be included in one averaging plan.

(4) Each unit included in an averaging plan shall have a minimum allowable annual heat input value (mmBtu), if it has an alternative contemporaneous annual emission limitation more stringent than that unit's applicable emission limitation under §§ 76.5, 76.6, or 76.7, and a maximum allowable annual heat input value, if it has an alternative contemporaneous annual emission limitation less stringent than that unit's applicable emission limitation under §§ 76.5, 76.6, or 76.7.

(5) The Btu-weighted annual average emission rate for the units in an averaging plan shall be less than or equal to the Btu-weighted annual average emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in §§ 76.5, 76.6, or 76.7.

(6) In order to demonstrate that the proposed plan is consistent with paragraph (a)(5) of this section, the alternative contemporaneous annual emission limitations and annual heat input values assigned to the units in the proposed averaging plan shall meet the following requirement:

$$\frac{\sum_{i=1}^{n}(R_{Li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \leq \frac{\sum_{i=1}^{n}(R_{li} \times HI_i)}{\sum_{i=1}^{n} HI_i} \qquad \text{(Equation 1)}$$

Where:

R_{Li} = Alternative contemporaneous annual emission limitation for unit i, lb/mmBtu, as specified in the averaging plan;

R_{li} = Applicable emission limitation for unit i, lb/mmBtu, as specified in §§ 76.5, 76.6, or 76.7 except that for early election units, which may be included in an averaging plan only on or after January 1, 2000, R_{li} shall equal the most stringent applicable emission limitation under §§ 76.5 or 76.7;

HI_i = Annual heat input for unit i, mmBtu, as specified in the averaging plan;

n = Number of units in the averaging plan.

(7) For units with an alternative emission limitation, R_{li} shall equal the applicable emissions limitation under §§ 76.5, 76.6, or 76.7, not the alternative emissions limitation.

(8) No unit may be included in more than one averaging plan.

(b)(1) *Submission requirements.* The designated representative of a unit meeting the requirements of paragraphs (a)(1), (a)(2), and (a)(8) of this section may submit an averaging plan (or a revision to an approved averaging plan) to the permitting authority(ies) at any time up to and including January 1 (or July 1, if the plan is restricted to units located within a single permitting authority's jurisdiction) of the calendar year for which the averaging plan is to become effective.

(2) The designated representative shall submit a copy of the same averaging plan (or the same revision to an approved averaging plan) to each permitting authority with jurisdiction over a unit in the plan.

(3) When an averaging plan (or a revision to an approved averaging plan) is not approved, the owner or operator of each unit in the plan shall operate the unit in compliance with the emission limitation that would apply in the absence of the averaging plan (or revision to a plan).

(c) *Contents of NO_X averaging plan.* A complete NO_X averaging plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of each unit in the plan;

(2) Each unit's applicable emission limitation in §§ 76.5, 76.6, or 76.7;

(3) The alternative contemporaneous annual emission limitation for each unit (in lb/mmBtu). If any of the units identified in the NO_X averaging plan utilize a common stack pursuant to § 75.17(a)(2)(i)(B) of this chapter, the same alternative contemporaneous emission limitation shall be assigned to each such unit and different heat input limits may be assigned;

(4) The annual heat input limit for each unit (in mmBtu);

(5) The calculation for Equation 1 in paragraph (a)(6) of this section;

(6) The calendar years for which the plan will be in effect; and

(7) The special provisions in paragraph (d)(1) of this section.

(d) *Special provisions.—(1) Emission limitations.* Each affected unit in an approved averaging plan is in compliance with the Acid Rain emission limitation for NO_X under the plan only if the following requirements are met:

(i) For each unit, the unit's actual annual average emission rate for the calendar year, in lb/mmBtu, is less than or equal to its alternative contemporaneous annual emission limitation in the averaging plan; and

(A) For each unit with an alternative contemporaneous emission limitation less stringent than the applicable emission limitation in §§ 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year does not exceed the annual heat input limit in the averaging plan;

(B) For each unit with an alternative contemporaneous annual emission limitation more stringent than the applicable emission limitation in §§ 76.5, 76.6, or 76.7, the actual annual heat input for the calendar year is not less than the annual heat input limit in the averaging plan; or

(ii) If one or more of the units does not meet the requirements under paragraph (d)(1)(i) of this section, the designated representative shall demonstrate, in accordance with paragraph (d)(1)(ii)(A) of this section (Equation 2) that the actual Btu-weighted annual average emission rate for the units in the plan is less than or equal to the Btu-weighted annual average rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations in §§ 76.5, 76.6, or 76.7.

(A) A group showing of compliance shall be made based on the following equation:

$$\frac{\sum_{i=1}^{n}(R_{ai}\times HI_{ai})}{\sum_{i=1}^{n}HI_{ai}} \le \frac{\sum_{i=1}^{n}(R_{li}\times HI_{ai})}{\sum_{i=1}^{n}HI_{ai}} \qquad \text{(Equation 2)}$$

Where:

R_{ai} = Actual annual average emission rate for unit i, lb/mmBtu, as determined using the procedures in part 75 of this chapter. For units in an averaging plan utilizing a common stack pursuant to § 75.17(a)(2)(i)(B) of this chapter, use the same NO_X emission rate value for each unit utilizing the common stack, and calculate this value in accordance with appendix F to part 75 of this chapter;

R_{li} = Applicable annual emission limitation for unit i lb/mmBtu, as specified in §§ 76.5, 76.6, or 76.7, except that for early election units, which may be included in an averaging plan only on or after January 1, 2000, R_{li} shall equal the most stringent applicable emission limitation under §§ 76.5 or 76.7;

HI_{ai} = Actual annual heat input for unit i, mmBtu, as determined using the procedures in part 75 of this chapter;

n = Number of units in the averaging plan.

(B) For units with an alternative emission limitation, R_{li} shall equal the applicable emission limitation under §§ 76.5, 76.6, or 76.7, not the alternative emission limitation.

(C) If there is a successful group showing of compliance under paragraph (d)(1)(ii)(A) of this section for a calendar year, then all units in the averaging plan shall be deemed to be in compliance for that year with their alternative contemporaneous emission limitations and annual heat input limits under paragraph (d)(1)(i) of this section.

(2) *Liability.* The owners and operators of a unit governed by an approved averaging plan shall be liable for any violation of the plan or this section at that unit or any other unit in the plan, including liability for fulfilling the obligations specified in part 77 of this chapter and sections 113 and 411 of the Act.

(3) *Withdrawal or termination.* The designated representative may submit a notification to terminate an approved averaging plan in accordance with § 72.40(d) of this chapter, no later than October 1 of the calendar year for which the plan is to be withdrawn or terminated.

§ 76.12 Phase I NO_X compliance extension.

(a) *General provisions.* (1) The designated representative of a Phase I unit with a Group 1 boiler may apply for and receive a 15-month extension of the deadline for meeting the applicable emissions limitation under § 76.5 where it is demonstrated, to the satisfaction of the Administrator, that:

(i) The low NO_X burner technology designed to meet the applicable emission limitation is not in adequate supply to enable installation and operation at the unit, consistent with system reliability, by January 1, 1995 and the reliability problems are due substantially to NO_X emission control system installation and availability; or

(ii) The unit is participating in an approved clean coal technology demonstration project.

(2) In order to obtain a Phase I NO_X compliance extension, the designated representative shall submit a Phase I

NO_X compliance extension plan by October 1, 1994.

(b) *Contents of Phase I NO_X compliance extension plan.* A complete Phase I NO_X compliance extension plan shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the unit.

(2) For units applying pursuant to paragraph (a)(1)(i) of this section:

(i) A list of the company names, addresses, and telephone numbers of vendors who are qualified to provide the services and low NO_X burner technology designed to meet the applicable emission limitation under § 76.5 and have been contacted to obtain the required services and technology. The list shall include the dates of contact, and a copy of each request for bids shall be submitted, along with any other information necessary to show a good-faith effort to obtain the required services and technology necessary to meet the requirements of this part on or before January 1, 1995.

(ii) A copy of those portions of a legally binding contract with a qualified vendor that demonstrate that services and low NO_X burner technology designed to meet the applicable emission limitation under § 76.5, with a completion date not later than December 31, 1995 have been contracted for.

(iii) Scheduling information, including justification and test schedules.

(iv) To demonstrate, if applicable, that the supply of the low NO_X burner technology designed to meet the applicable emission limitation under § 76.5 is inadequate to enable its installation and operation at the unit, consistent with system reliability, in time for the unit to comply with the applicable emission limitation on or before January 1, 1995, either:

(A) Certification from the selected vendor(s) (by a certifying official) listed in paragraph (b)(2)(i) of this section stating that they cannot provide the necessary services and install the low NO_X burner technology on or before January 1, 1995 and explaining the reasons why the services cannot be provided and why the equipment cannot be installed in a timely manner; or

(B) The following information:

(i) Standard load forecasts, based on standard forecasting models available throughout the utility industry and applied to the period, January 1, 1993, through December 31, 1994.

(ii) Specific reasons why an outage cannot be scheduled to enable the unit to install and operate the low NO_X burner technology by January 1, 1995, including reasons why no other units can be used to replace this unit's generation during such outage.

(iii) Fuel and energy balance summaries and power and other consumption requirements (including those for air, steam, and cooling water).

(3) To demonstrate, if applicable, participation in an approved clean coal technology demonstration project, a description of the project, including all sources of federal, State, and other outside funding, amount and date for approval of federal funding, the duration of the project, and the anticipated completion date of the project.

(4) The special provisions in paragraph (d) of this section.

(c) (1) *Administrator's action.* To the extent the Administrator determines that a Phase I NO_X compliance extension plan complies with the requirements of this section, the Administrator will approve the plan and revise the Acid Rain permit governing the unit in the plan in order to incorporate the plan by administrative amendment under § 72.83 of this chapter, except that the Administrator shall have 90 days from receipt of the compliance extension plan to take final action.

(2) The Administrator will approve or disapprove a proposed NO_X compliance extension plan within 3 months of receipt.

(d) *Special provisions.*

(1) Emission limitations. The unit shall comply with the applicable emission limitation under § 76.5 beginning April 1, 1996. Compliance shall be determined as specified in part 75 of this chapter using measured values of NO_X emissions and heat input only for the portion of the year that the emission limit is in effect.

(2) If a unit with an approved NO_X compliance extension is included in an averaging plan under § 76.11 for year 1996, the unit shall be treated, for purposes of applying Equation 1 in § 76.11(a)(6) and Equation 2 in § 76.11(d)(1)(ii)(A), as subject to the applicable emission limitation under § 76.5 for the entire year 1996.

(e) *Extension until December 31, 1997.* (1) The designated representative of a Phase I unit that is subject to section 404(d) of the Act, has a tangentially fired boiler, and is unable to install low NO_X burner technology by January 1, 1997 may submit a petition for and receive an extension for meeting the applicable emission limitation under § 76.5 where it is demonstrated, to the satisfaction of the Administrator, that:

(i) The unit is located at a source with two or more other units, all of which are Phase I units that are subject to section 404(d) of the Act and have tangentially fired boilers;

(ii) The NO_X control system at the unit was scheduled to be installed by January 1, 1997 and, because of operational problems associated with the NO_X control system, will be redesigned; and

(iii) Installation of the redesigned low NO_X burner technology at the unit cannot be completed by January 1, 1997 without causing system reliability problems.

(2) A complete petition shall include the following elements and shall be submitted by April 28, 1995.

(i) Identification of the unit and the other units at the source;

(ii) A statement describing how the requirements of paragraphs (e)(1)(ii) and (e)(1)(iii) of this section are met;

(iii) The earliest date, not later than December 31, 1997, by which installation of the redesigned low NO_X burner technology can be completed consistent with system reliability; and

(iv) The provisions in paragraph (e)(4) of this section.

(3) To the extent the Administrator determines that a Phase I unit meets the requirements of paragraphs (e)(1) and (e)(2) of this section, the Administrator will approve the petition within 90 days from receipt of the complete petition. The Acid Rain permit governing the unit will be revised in order to incorporate the approved extension, which shall terminate no later than December 31, 1997, by administrative amendment under § 72.83 of this chapter except that the Administrator will have 90 days to take final action.

(4) The unit shall comply with the applicable emission limitation under § 76.5 beginning on the day immediately following the day on which the extension approved under paragraph (e)(3) of this section terminates. Compliance shall be determined as specified in part 75 of this chapter using measured values of NO_X emissions and heat input only for the portion of the year that the emission limit is in effect. If a unit with an approved extension is included in an averaging plan under § 76.11 for year 1997, the unit shall be treated, for the purpose of applying Equation 1 in § 76.11(a)(6) and Equation 2 in § 76.11(d)(1)(ii)(A), as subject to the applicable emission limitation under § 76.5 for the entire year 1997.

§ 76.13 Compliance and excess emissions.

Excess emissions of nitrogen oxides under § 77.6 of this chapter shall be calculated as follows:

(a) For a unit that is not in an approved averaging plan:

(1) Calculate EE_i for each portion of the calendar year that the unit is subject to a different NO_X emission limitation:

$$EE_i = \frac{(R_{ai} - R_{li}) \times HI_i}{2000} \qquad \text{(Equation 3)}$$

Where:

EE_i = Excess emissions for NO_X for the portion of the calendar year (in tons);

R_{ai} = Actual average emission rate for the unit (in lb/mmBtu), determined according to part 75 of this chapter for the portion of the calendar year for which the applicable emission limitation R_i is in effect;

R_{li} = Applicable emission limitation for the unit, (in lb/mmBtu), as specified in §§ 76.5, 76.6, or 76.7 or as determined under § 76.10;

$$EE = \sum_{i=1}^{n} EE_i \qquad \text{(Equation 4)}$$

HI_i = Actual heat input for the unit, (in mmBtu), determined according to part 75 of this chapter for the portion of the calendar year for which the applicable emission limitation, R_i, is in effect.

(2) If EE_i is a negative number for any portion of the calendar year, the EE value for that portion of the calendar year shall be equal to zero (e.g., if EE_i = −100, then EE_i = 0).

(3) Sum all EE_i values for the calendar year:

Where:

EE = Excess emissions for NO_X for the year (in tons);

n = The number of time periods during which a unit is subject to different emission limitations; and

(b) For units participating in an approved averaging plan, when all the requirements under § 76.11(d)(1) are not met,

$$EE = \frac{\sum_{i=1}^{n}(R_{ai} \times HI_i) - \sum_{i=1}^{n}(R_{li} \times HI_i)}{2000} \qquad \text{(Equation 5)}$$

Where:

EE = Excess emissions for NO_X for the year (in tons);

R_{ai} = Actual annual average emission rate for NO_X for unit i, (in lb/mmBtu), determined according to part 75 of this chapter;

R_{li} = Applicable emission limitation for unit i, (in lb/mmBtu), as specified in §§ 76.5, 76.6, or 76.7;

HI_i = Actual annual heat input for unit i, mmBtu, determined according to part 75 of this chapter:

n = Number of units in the averaging plan.

§ 76.14 Monitoring, recordkeeping, and reporting.

(a) A petition for an alternative emission limitation demonstration period under § 76.10(d) shall include the following information:

(1) In accordance with § 76.10(d)(4), the following information:

(i) Documentation that the owner or operator solicited bids for a NO_X emission control system designed for application to the specific boiler and designed to achieve the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis. This documentation must include a copy of all bid specifications.

(ii) A copy of the performance guarantee submitted by the vendor of the installed NO_X emission control system to the owner or operator showing that such system was designed to meet the applicable emission limitation in §§ 76.5, 76.6, or 76.7 on an annual average basis.

(iii) Documentation describing the operational and combustion conditions that are the basis of the performance guarantee.

(iv) Certification by the primary vendor of the NO_X emission control system that such equipment and associated auxiliary equipment was properly installed according to the modifications and procedures specified by the vendor.

(v) Certification by the designated representative that the owner(s) or operator installed technology that meets the requirements of § 76.10(a)(2).

(2) In accordance with § 76.10(d)(9), the following information:

(i) The operating conditions of the NO_X emission control system including load range, O_2 range, coal volatile matter range, and, for tangentially fired boilers, distribution of combustion air within the NO_X emission control system;

(ii) Certification by the designated representative that the owner(s) or operator have achieved and are following the operating conditions, boiler modifications, and upgrades that formed the basis for the system design and performance guarantee;

(iii) Any planned equipment modifications and upgrades for the purpose of achieving the maximum NO_X reduction performance of the NO_X emission control system that were not included in the design specifications and performance guarantee, but that were achieved prior to submission of this application and are being followed;

(iv) A list of any modifications or replacements of equipment that are to be done prior to the completion of the demonstration period for the purpose of reducing emissions of NO_X; and

(v) The parametric testing that will be conducted to determine the reason or reasons for the failure of the unit to achieve the applicable emission limitation and to verify the proper operation of the installed NO_X emission control system during the demonstration period. The tests shall include tests in § 76.15, which may be modified as follows:

(A) The owner or operator of the unit may add tests to those listed in § 76.15, if such additions provide data relevant to the failure of the installed NO_X emission control system to meet the applicable emissions limitation in §§ 76.5, 76.6, or 76.7; or

(B) The owner or operator of the unit may remove tests listed in § 76.15 that are shown, to the satisfaction of the permitting authority, not to be relevant to NO_X emissions from the affected unit; and

(C) In the event the performance guarantee or the NO_X emission control system specifications require additional tests not listed in § 76.15, or specify operating conditions not verified by tests listed in § 76.15, the owner or operator of the unit shall include such additional tests.

(3) In accordance with § 76.10(d)(10), the following information for the operating period:

(i) The average NO_X emission rate (in lb/mmBtu) of the specific unit;

(ii) The highest hourly NO_X emission rate (in lb/mmBtu) of the specific unit;

(iii) Hourly NO_X emission rate (in lb/mmBtu), calculated in accordance with part 75 of this chapter;

(iv) Total heat input (in mmBtu) for the unit for each hour of operation.

calculated in accordance with the requirements of part 75 of this chapter; and

(v) Total integrated hourly gross unit load (in MWge).

(b) A petition for an alternative emission limitation shall include the following information in accordance with § 76.10(e)(6).

(1) Total heat input (in mmBtu) for the unit for each hour of operation, calculated in accordance with the requirements of part 75 of this chapter;

(2) Hourly NO_X emission rate (in lb/mmBtu), calculated in accordance with the requirements of part 75 of this chapter; and

(3) Total integrated hourly gross unit load (MWge).

(c) *Reporting of the costs of low NO_X burner technology applied to Group 1, Phase I boilers.* (1) Except as provided in paragraph (c)(2) of this section, the designated representative of a Phase I unit with a Group 1 boiler that has installed or is installing any form of low NO_X burner technology shall submit to the Administrator a report containing the capital cost, operating cost, and baseline and post-retrofit emission data specified in appendix B to this part. If any of the required equipment, cost, and schedule information are not available (e.g., the retrofit project is still underway), the designated representative shall include in the report detailed cost estimates and other projected or estimated data in lieu of the information that is not available.

(2) The report under paragraph (c)(1) of this section is not required with regard to the following types of Group 1, Phase I units:

(i) Units employing no new NO_X emission control system after November 15, 1990;

(ii) Units employing modifications to boiler operating parameters (e.g., burners out of service or fuel switching) without low NO_X burners or other emission reduction equipment for reducing NO_X emissions;

(iii) Units with wall-fired boilers employing only overfire air and units with tangentially fired boilers employing only separated overfire air; or

(iv) Units beginning installation of a new NO_X emission control system after August 11, 1995.

(3) The report under paragraph (c)(1) of this section shall be submitted to the Administrator by:

(i) 120 days after completion of the low NO_X burner technology retrofit project; or

(ii) May 23, 1995, if the project was completed on or before January 23, 1995.

§ 76.15 Test methods and procedures.

(a) The owner or operator may use the following tests as a basis for the report required by § 76.10(e)(7):

(1) Conduct an ultimate analysis of coal using ASTM D 3176–89 (incorporated by reference as specified in § 76.4);

(2) Conduct a proximate analysis of coal using ASTM D 3172–89 (incorporated by reference as specified in § 76.4); and

(3) Measure the coal mass flow rate to each individual burner using ASME Power Test Code 4.2 (1991), "Test Code for Coal Pulverizers" or ISO 9931 (1991), "Coal—Sampling of Pulverized Coal Conveyed by Gases in Direct Fired Coal Systems" (incorporated by reference as specified in § 76.4).

(b) The owner or operator may measure and record the actual NO_X emission rate in accordance with the requirements of this part while varying the following parameters where possible to determine their effects on the emissions of NO_X from the affected boiler:

(1) Excess air levels;

(2) Settings of burners or coal and air nozzles, including tilt and yaw, or swirl;

(3) For tangentially fired boilers, distribution of combustion air within the NO_X emission control system;

(4) Coal mass flow rates to each individual burner;

(5) Coal-to-primary air ratio (based on pound per hour) for each burner, the average coal-to-primary air ratio for all burners, and the deviations of individual burners' coal-to-primary air ratios from the average value; and

(6) If the boiler uses varying types of coal, the type of coal. Provide the results of proximate and ultimate analyses of each type of as-fired coal.

(c) In performing the tests specified in paragraph (a) of this section, the owner or operator shall begin the tests using the equipment settings for which the NO_X emission control system was designed to meet the NO_X emission rate guaranteed by the primary NO_X emission control system vendor. These results constitute the "baseline controlled" condition.

(d) After establishing the baseline controlled condition under paragraph (c) of this section, the owner or operator may:

(1) Change excess air levels ± 5 percent from the baseline controlled condition to determine the effects on emissions of NO_X, by providing a minimum of three readings (e.g., with a baseline reading of 20 percent excess air, excess air levels will be changed to 19 percent and 21 percent);

(2) For tangentially fired boilers, change the distribution of combustion air within the NO_X emission control system to determine the effects on NO_X emissions by providing a minimum of three readings, one with the minimum, one with the baseline, and one with the maximum amounts of staged combustion air; and

(3) Show that the combustion process within the boiler is optimized (e.g., that the burners are balanced).

§ 76.16 [Reserved]

Appendix A to Part 76—Phase I Affected Coal-Fired Utility Units With Group 1 or Cell Burner Boilers

TABLE 1.—PHASE I TANGENTIALLY FIRED UNITS

State	Plant	Unit	Operator
ALABAMA	EC GASTON	5	ALABAMA POWER CO.
GEORGIA	BOWEN	1BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	2BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	3BLR	GEORGIA POWER CO.
GEORGIA	BOWEN	4BLR	GEORGIA POWER CO.
GEORGIA	JACK MCDONOUGH	MB1	GEORGIA POWER CO.
GEORGIA	JACK MCDONOUGH	MB2	GEORGIA POWER CO.
GEORGIA	WANSLEY	1	GEORGIA POWER CO.
GEORGIA	WANSLEY	2	GEORGIA POWER CO.
GEORGIA	YATES	Y1BR	GEORGIA POWER CO.
GEORGIA	YATES	Y2BR	GEORGIA POWER CO.
GEORGIA	YATES	Y3BR	GEORGIA POWER CO.
GEORGIA	YATES	Y4BR	GEORGIA POWER CO.
GEORGIA	YATES	Y5BR	GEORGIA POWER CO.

TABLE 1.—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
GEORGIA	YATES	Y6BR	GEORGIA POWER CO.
GEORGIA	YATES	Y7BR	GEORGIA POWER CO.
ILLINOIS	BALDWIN	3	ILLINOIS POWER CO.
ILLINOIS	HENNEPIN	2	ILLINOIS POWER CO.
ILLINOIS	JOPPA	1	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	2	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	3	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	4	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	5	ELECTRIC ENERGY INC.
ILLINOIS	JOPPA	6	ELECTRIC ENERGY INC.
ILLINOIS	MEREDOSIA	5	CEN ILLINOIS PUB SER.
ILLINOIS	VERMILION	2	ILLINOIS POWER CO.
INDIANA	CAYUGA	1	PSI ENERGY INC.
INDIANA	CAYUGA	2	PSI ENERGY INC.
INDIANA	EW STOUT	50	INDIANAPOLIS PWR & LT.
INDIANA	EW STOUT	60	INDIANAPOLIS PWR & LT.
INDIANA	EW STOUT	70	INDIANAPOLIS PRW & LT.
INDIANA	HT PRITCHARD	6	INDIANAPOLIS PWR & LT.
INDIANA	PETERSBURG	1	INDIANAPOLIS PWR & LT.
INDIANA	PETERSBURG	2	INDIANAPOLIS PWR & LT.
INDIANA	WABASH RIVER	6	PSI ENERGY INC.
IOWA	BURLINGTON	1	IOWA SOUTHERN UTL.
IOWA	ML KAPP	2	INTERSTATE POWER CO.
IOWA	RIVERSIDE	9	IOWA-ILL GAS & ELEC.
KENTUCKY	ELMER SMITH	2	OWENSBORO MUN UTIL.
KENTUCKY	EW BROWN	2	KENTUCKY UTL CO.
KENTUCKY	EW BROWN	3	KENTUCKY UTL CO.
KENTUCKY	GHENT	1	KENTUCKY UTL CO.
MARYLAND	MORGANTOWN	1	POTOMAC ELEC PWR CO.
MARYLAND	MORGANTOWN	2	POTOMAC ELEC PWR CO.
MICHIGAN	JH CAMPBELL	1	CONSUMERS POWER CO.
MISSOURI	LABADIE	1	UNION ELECTRIC CO.
MISSOURI	LABADIE	2	UNION ELECTRIC CO.
MISSOURI	LABADIE	3	UNION ELECTRIC CO.
MISSOURI	LABADIE	4	UNION ELECTRIC CO.
MISSOURI	MONTROSE	1	KANSAS CITY PWR & LT.
MISSOURI	MONTROSE	2	KANSAS CITY PWR & LT.
MISSOURI	MONTROSE	3	KANSAS CITY PWR & LT.
NEW YORK	DUNKIRK	3	NIAGARA MOHAWK PWR.
NEW YORK	DUNKIRK	4	NIAGARA MOHAWK PWR.
NEW YORK	GREENIDGE	6	NY STATE ELEC & GAS.
NEW YORK	MILLIKEN	1	NY STATE ELEC & GAS.
NEW YORK	MILLIKEN	2	NY STATE ELEC & GAS.
OHIO	ASHTABULA	7	CLEVELAND ELEC ILLUM.
OHIO	AVON LAKE	11	CLEVELAND ELEC ILLUM.
OHIO	CONESVILLE	4	COLUMBUS STHERN PWR.
OHIO	EASTLAKE	1	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	2	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	3	CLEVELAND ELEC ILLUM.
OHIO	EASTLAKE	4	CLEVELAND ELEC ILLUM.
OHIO	MIAMI FORT	6	CINCINNATI GAS & ELEC.
OHIO	WC BECKJORD	5	CINCINNATI GAS & ELEC.
OHIO	WC BECKJORD	6	CINCINNATI GAS & ELEC.
PENNSYLVANIA	BRUNNER ISLAND	1	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	BRUNNER ISLAND	2	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	BRUNNER ISLAND	3	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	CHESWICK	1	DUQUESNE LIGHT CO.
PENNSYLVANIA	CONEMAUGH	1	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	CONEMAUGH	2	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	PORTLAND	1	METROPOLITAN EDISON
PENNSYLVANIA	PORTLAND	2	METROPOLITAN EDISON.
PENNSYLVANIA	SHAWVILLE	3	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SHAWVILLE	4	PENNSYLVANIA ELEC CO.
TENNESSEE	GALLATIN	1	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	2	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	3	TENNESSEE VAL AUTH.
TENNESSEE	GALLATIN	4	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	1	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	2	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	3	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	4	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	5	TENNESSEE VAL AUTH.

TABLE 1.—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
TENNESSEE	JOHNSONVILLE	6	TENNESSEE VAL AUTH.
WEST VIRGINIA	ALBRIGHT	3	MONONGAHELA POWER CO.
WEST VIRGINIA	FORT MARTIN	1	MONONGAHELA POWER CO.
WEST VIRGINIA	MOUNT STORM	1	VIRGINIA ELEC & PWR.
WEST VIRGINIA	MOUNT STORM	2	VIRGINIA ELEC & PWR.
WEST VIRGINIA	MOUNT STORM	3	VIRGINIA ELEC & PWR.
WISCONSIN	GENOA	1	DAIRYLAND POWER COOP.
WISCONSIN	SOUTH OAK CREEK	7	WISCONSIN ELEC POWER.
WISCONSIN	SOUTH OAK CREEK	8	WISCONSIN ELEC POWER.

TABLE 2.—PHASE I DRY BOTTOM-FIRED UNITS

State	Plant	Unit	Operator
ALABAMA	COLBERT	1	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	2	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	3	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	4	TENNESSEE VAL AUTH.
ALABAMA	COLBERT	5	TENNESSEE VAL AUTH.
ALABAMA	EC GASTON	1	ALABAMA POWER CO.
ALABAMA	EC GASTON	2	ALABAMA POWER CO.
ALABAMA	EC GASTON	3	ALABAMA POWER CO.
ALABAMA	EC GASTON	4	ALABAMA POWER CO.
FLORIDA	CRIST	6	GULF POWER CO.
FLORIDA	CRIST	7	GULF POWER CO.
GEORGIA	HAMMOND	1	GEORGIA POWER CO.
GEORGIA	HAMMOND	2	GEORGIA POWER CO.
GEORGIA	HAMMOND	3	GEORGIA POWER CO.
GEORGIA	HAMMOND	4	GEORGIA POWER CO.
ILLINOIS	GRAND TOWER	9	CEN ILLINOIS PUB SER.
INDIANA	CULLEY	2	STHERN IND GAS & EL.
INDIANA	CULLEY	3	STHERN IND GAS & EL.
INDIANA	GIBSON	1	PSI ENERGY INC.
INDIANA	GIBSON	2	PSI ENERGY INC.
INDIANA	GIBSON	3	PSI ENERGY INC.
INDIANA	GIBSON	4	PSI ENERGY INC.
INDIANA	RA GALLAGHER	1	PSI ENERGY INC.
INDIANA	RA GALLAGHER	2	PSI ENERGY INC.
INDIANA	RA GALLAGHER	3	PSI ENERGY INC.
INDIANA	RA GALLAGHER	4	PSI ENERGY INC.
INDIANA	FRANK E RATTS	1SG1	HOOSIER ENERGY REC.
INDIANA	FRANK E RATTS	2SG1	HOOSIER ENERGY REC.
INDIANA	WABASH RIVER	1	PSI ENERGY INC.
INDIANA	WABASH RIVER	2	PSI ENERGY INC.
INDIANA	WABASH RIVER	3	PSI ENERGY INC.
INDIANA	WABASH RIVER	5	PSI ENERGY INC.
IOWA	DES MOINES	11	IOWA PWR & LT CO.
IOWA	PRAIRIE CREEK	4	IOWA ELEC LT & PWR.
KANSAS	QUINDARO	2	KS CITY BD PUB UTIL.
KENTUCKY	COLEMAN	C1	BIG RIVERS ELEC CORP.
KENTUCKY	COLEMAN	C2	BIG RIVERS ELEC CORP.
KENTUCKY	COLEMAN	C3	BIG RIVERS ELEC CORP.
KENTUCKY	EW BROWN	1	KENTUCKY UTL CO.
KENTUCKY	GREEN RIVER	5	KENTUCKY UTL CO.
KENTUCKY	HMP&L STATION 2	H1	BIG RIVERS ELEC CORP.
KENTUCKY	HMP&L STATION 2	H2	BIG RIVERS ELEC CORP.
KENTUCKY	HL SPURLOCK	1	EAST KY PWR COOP.
KENTUCKY	JS COOPER	1	EAST KY PWR COOP.
KENTUCKY	JS COOPER	2	EAST KY PWR COOP.
MARYLAND	CHALK POINT	1	POTOMAC ELEC PWR CO.

TABLE 2.—PHASE I DRY BOTTOM-FIRED UNITS—Continued

State	Plant	Unit	Operator
MARYLAND	CHALK POINT	2	POTOMAC ELEC PWR CO.
MINNESOTA	HIGH BRIDGE	6	NORTHERN STATES PWR.
MISSISSIPPI	JACK WATSON	4	MISSISSIPPI PWR CO.
MISSISSIPPI	JACK WATSON	5	MISSISSIPPI PWR CO.
MISSOURI	JAMES RIVER	5	SPRINGFIELD UTL.
OHIO	CONESVILLE	3	COLUMBUS STHERN PWR.
OHIO	EDGEWATER	13	OHIO EDISON CO.
OHIO	MIAMI FORT [1]	5–1	CINCINNATI GAS&ELEC.
OHIO	MIAMI FORT [1]	5–2	CINCINNATI GAS&ELEC.
OHIO	PICWAY	9	COLUMBUS STHERN PWR.
OHIO	RE BURGER	7	OHIO EDISON CO.
OHIO	RE BURGER	8	OHIO EDISON CO.
OHIO	WH SAMMIS	5	OHIO EDISON CO.
OHIO	WH SAMMIS	6	OHIO EDISON CO.
PENNSYLVANIA	ARMSTRONG	1	WEST PENN POWER CO.
PENNSYLVANIA	ARMSTRONG	2	WEST PENN POWER CO.
PENNSYLVANIA	MARTINS CREEK	1	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	MARTINS CREEK	2	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	SHAWVILLE	1	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SHAWVILLE	2	PENNSYLVANIA ELEC CO.
PENNSYLVANIA	SUNBURY	3	PENNSYLVANIA PWR & LT.
PENNSYLVANIA	SUNBURY	4	PENNSYLVANIA PWR & LT.
TENNESSEE	JOHNSONVILLE	7	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	8	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	9	TENNESSEE VAL AUTH.
TENNESSEE	JOHNSONVILLE	10	TENNESSEE VAL AUTH.
WEST VIRGINIA	HARRISON	1	MONONGAHELA POWER CO.
WEST VIRGINIA	HARRISON	2	MONONGAHELA POWER CO.
WEST VIRGINIA	HARRISON	3	MONONGAHELA POWER CO.
WEST VIRGINIA	MITCHELL	1	OHIO POWER CO.
WEST VIRGINIA	MITCHELL	2	OHIO POWER CO.
WISCONSIN	JP PULLIAM	8	WISCONSIN PUB SER CO.
WISCONSIN	NORTH OAK CREEK [2]	1	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	2	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	3	WISCONSIN ELEC PWR.
WISCONSIN	NORTH OAK CREEK [2]	4	WISCONSIN ELEC PWR.
WISCONSIN	SOUTH OAK CREEK [2]	5	WISCONSIN ELEC PWR.
WISCONSIN	SOUTH OAK CREEK [2]	6	WISCONSIN ELEC PWR.

[1] Vertically fired boiler.
[2] Arch-fired boiler.

TABLE 3.—PHASE I CELL BURNER TECHNOLOGY UNITS

State	Plant	Unit	Operator
INDIANA	WARRICK	4	STHERN IND GAS & EL.
MICHIGAN	JH CAMPBELL	2	CONSUMERS POWER CO.
OHIO	AVON LAKE	12	CLEVELAND ELEC ILLUM.
OHIO	CARDINAL	1	CARDINAL OPERATING.
OHIO	CARDINAL	2	CARDINAL OPERATING.
OHIO	EASTLAKE	5	CLEVELAND ELEC ILLUM.
OHIO	GENRL JM GAVIN	1	OHIO POWER CO.
OHIO	GENRL JM GAVIN	2	OHIO POWER CO.
OHIO	MIAMI FORT	7	CINCINNATI GAS & EL.
OHIO	MUSKINGUM RIVER	5	OHIO POWER CO.
OHIO	WH SAMMIS	7	OHIO EDISON CO.
PENNSYLVANIA	HATFIELDS FERRY	1	WEST PENN POWER CO.
PENNSYLVANIA	HATFIELDS FERRY	2	WEST PENN POWER CO.
PENNSYLVANIA	HATFIELDS FERRY	3	WEST PENN POWER CO.
TENNESSEE	CUMBERLAND	1	TENNESSEE VAL AUTH.
TENNESSEE	CUMBERLAND	2	TENNESSEE VAL AUTH.
WEST VIRGINIA	FORT MARTIN	2	MONONGAHELA POWER CO.

Appendix B to Part 76—Procedures and Methods for Estimating Costs of Nitrogen Oxides Controls Applied to Group 1, Phase I Boilers

1. Purpose and Applicability

This technical appendix specifies the procedures, methods, and data that the Administrator will use in establishing "* * * the degree of reduction achievable through this retrofit application of the best system of continuous emission reduction, taking into account available technology, costs, and energy and environmental impacts; and which is comparable to the costs of nitrogen oxides controls set pursuant to subsection (b)(1) (of section 407 of the Act)." In developing the allowable NO_X emissions limitations for Group 2 boilers pursuant to subsection (b)(2) of section 407 of the Act, the Administrator will consider only those systems of continuous emission reduction that, when applied on a retrofit basis, are comparable in cost to the average cost in constant dollars of low NO_X burner technology applied to Group 1, Phase I boilers, as determined in section 3 below.

The Administrator will evaluate the capital cost (in dollars per kilowatt electrical ($/kW)), the operating and maintenance costs (in $/year), and the cost-effectiveness (in annualized $/ton NO_X removed) of installed low NO_X burner technology controls over a range of boiler sizes (as measured by the gross electrical capacity of the associated generator in megawatt electrical (MW)) and utilization rates (in percent gross nameplate capacity on an annual basis) to develop estimates of the average capital cost and cost-effectiveness for Group 1, Phase I boilers. The following units will be excluded from these determinations of the average capital cost and cost-effectiveness of NO_X controls set pursuant to subsection (b)(1) of section 407 of the Act: (1) Units employing an alternative technology, or only overfire air as applied to wall-fired boilers or only separated overfire air as applied to tangentially fired boilers, in lieu of low NO_X burner technology for reducing NO_X emissions; (2) units employing no controls, only controls installed before November 15, 1990, or only modifications to boiler operating parameters (e.g., burners out of service or fuel switching) for reducing NO_X emissions; and (3) units that have not achieved the applicable emission limitation.

2. Average Capital Cost for Low NO_X Burner Technology Applied to Group 1, Phase I Boilers

The Administrator will use the procedures, methods, and data specified in this section to estimate the average capital cost (in $/kW) of installed low NO_X burner technology applied to Group 1, Phase I boilers.

2.1 Using cost data submitted pursuant to the reporting requirements in section 4 below, boiler-specific actual or estimated actual capital costs will be determined for each unit in the population specified in section 1 above for assessing the costs of installed low NO_X burner technology. The scope of installed low NO_X burner technology costs will include the following capital costs for retrofit application: (1) For the burner portion—burners or air and coal nozzles, burner throat and waterwall modifications, and windbox modifications; and, where applicable, (2) for the combustion air staging portion—waterwall modifications or panels, windbox modifications, and ductwork, and (3) scope adders or supplemental equipment such as replacement or additional fans, dampers, or ignitors necessary for the proper operation of the low NO_X burner technology. Capital costs associated with boiler restoration or refurbishment such as replacement of air heaters, asbestos abatement, and recasing will not be included in the cost basis for installed low NO_X burner technology. The scope of installed low NO_X burner technology retrofit capital costs will include materials, construction and installation labor, engineering, and overhead costs.

2.2 Using gross nameplate capacity (in MW) for each unit as reported in the National Allowance Data Base (NADB), boiler-specific capital costs will be converted to a $/kW basis.

2.3 Capital cost curves ($/kW versus boiler size in MW) or equations for installed low NO_X burner technology retrofit costs will be developed for: (1) Dry bottom wall fired boilers (excluding units applying cell burner technology) and (2) tangentially fired boilers.

2.4 The capital cost curves or equations defined above will be used to develop weighted average cost estimates of installed low NO_X burner technology applied to Group 1, Phase I boilers. The weighting factor will be the unit gross nameplate generating capacity (in MW) as reported in the NADB.

3. Average Cost-Effectiveness for Low NO_X Burner Technology Applied to Group 1, Phase I Boilers

The Administrator will use the procedures, methods, and data specified in this section to estimate the average cost-effectiveness (in annualized $/ton NO_X removed) of installed low NO_X burner technology applied to Group 1, Phase I boilers.

3.1 Boiler-specific estimates of annual tons NO_X removed by the installed low NO_X burner technology will be determined for each unit in the population specified in section 1 above.

3.1.1 The baseline NO_X emission rate (in lb/mmBtu, annual average basis) will be estimated prior to retrofitting any low NO_X burner technology controls. For units that have installed and certified continuous emission monitoring systems for measuring the NO_X emission rate pursuant to part 75 of this chapter at least 120 days prior to the low NO_X burner technology retrofit, an estimate of the average annual uncontrolled NO_X emission rate will be developed using continuous emission monitoring data for the 120 days immediately before the low NO_X burner technology retrofit or another continuous 120-day or longer period as approved by the Administrator. (In cases where 120 days of certified and quality-assured continuous emission monitoring data are not available prior to the low NO_X burner technology retrofit, the Administrator may use continuous emission monitoring data over a shorter period or short-term test data to estimate the uncontrolled NO_X emission rate.) Continuous emission monitoring data or other emission rate measurements will be extrapolated to one year of unit operation.

3.1.2 The controlled NO_X emission rate (in lb/mmBtu, annual average basis) will be estimated after installation, shakedown, and/or optimization of all low NO_X burner technology controls have been completed and while the unit is complying with the applicable emission limitation (or alternative emission limitation). Continuous emission monitoring data submitted pursuant to part 75 of this chapter will be used for the 120 days immediately following installation and testing of the final low NO_X burner technology, provided the unit is complying with the applicable emission limitation (or alternative emission limitation), or another continuous 120-day or shorter period as approved by the Administrator. Continuous emission monitoring data will be extrapolated to one year of unit operation.

3.1.3 The NO_X emission reduction (in lb/mmBtu, annual average basis) achieved by the installed low NO_X burner technology will be estimated by subtracting the controlled NO_X emission rate defined in section 3.1.2 from the uncontrolled NO_X emission rate defined in section 3.1.1.

3.1.4 Annual estimates of the NO_X emission reduction achieved by the installed low NO_X burner technology will be converted to annual tons of NO_X removed by multiplying it by the annual heat input (in mmBtu). Unit heat input data submitted pursuant to part 75 of this chapter for calendar year 1994 or for the year immediately following installation and testing of the final low NO_X burner technology, will be used when such data are available prior to October 30, 1995. Such data will be adjusted to an annual basis whenever a nonrecurrent extended outage at the affected unit during the period has taken place.

3.2 The boiler-specific capital costs of installed low NO_X burner technology developed in section 2.1 will be annualized by multiplying them by a constant dollar capital recovery factor based on a 20-year economic life (e.g., 0.115).

3.3 Using cost data submitted pursuant to the reporting requirements in section 4, boiler-specific annual operating and maintenance cost increases (or decreases) will be determined for each unit in the population specified in section 1 above. The scope of the operating and maintenance costs (or savings) attributable to the installed low NO_X burner technology may, but not necessarily will, include incremental increases (or decreases) in: maintenance labor and materials costs, operating labor costs, operating fuel costs, and secondary air fan electricity costs.

3.4 The average annual cost-effectiveness of installed low NO_X burner technology applied to Group 1, Phase I boilers will be estimated as follows: (1) The annualized capital costs defined in section 3.2 and the annual operating and maintenance cost increases (or decreases) defined in section 3.3 will be summed for all units in the population specified in section 1; and (2) these annualized costs will be divided by the sum of the NO_X emission reductions (in tons/year) achieved by the units in the population specified in section 1.

4. Reporting Requirements

4.1 The following information is to be submitted by each designated representative of a Phase I affected unit subject to the reporting requirements of § 76.14(c):

4.1.1 Schedule and dates for baseline testing, installation, and performance testing of low NO_X burner technology.

4.1.2 Estimates of the annual average baseline NO_X emission rate, as specified in section 3.1.1, and the annual average controlled NO_X emission rate, as specified in section 3.1.2, including the supporting continuous emission monitoring or other test data.

4.1.3 Copies of pre-retrofit and post-retrofit performance test reports.

4.1.4 Detailed estimates of the capital costs based on actual contract bids for each component of the installed low NO_X burner technology including the items listed in section 2.1. Indicate number of bids solicited. Provide a copy of the actual agreement for the installed technology.

4.1.5 Detailed estimates of the capital costs of system replacements or upgrades such as coal pipe changes, fan replacements/upgrades, or mill replacements/upgrades undertaken as part of the low NO_X burner technology retrofit project.

4.1.6 Detailed breakdown of the actual costs of the completed low NO_X burner technology retrofit project where low NO_X burner technology costs (section 4.1.4) are disaggregated, if feasible, from system replacement or upgrade costs (section 4.1.5).

4.1.7 Description of the probable causes for significant differences between actual and estimated low NO_X burner technology retrofit project costs.

4.1.8 Detailed breakdown of the burner and, if applicable, combustion air staging system annual operating and maintenance costs for the items listed in section 3.3 before and after the installation, shakedown, and/or optimization of the installed low NO_X burner technology. Include estimates and a description of the probable causes of the incremental annual operating and maintenance costs (or savings) attributable to the installed low NO_X burner technology.

4.2 All capital cost estimates are to be broken down into materials costs, construction and installation labor costs, and engineering and overhead costs. All operating and maintenance costs are to be broken down into maintenance materials costs, maintenance labor costs, operating labor costs, and fan electricity costs. All capital and operating costs are to be reported in dollars with the year of expenditure or estimate specified for each component.

[FR Doc. 95–8742 Filed 4–12–95; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Public Land Order 7132

[AZ–930–1430–01; AR 06449]

Revocation of Public Land Order No. 1076; Arizona

AGENCY: Bureau of Land Management, Interior.

ACTION: Public Land Order.

SUMMARY: This order revokes a public land order which withdrew 240 acres of public land for use by the National Park Service in connection with the administration and maintenance of the Wupatki National Monument. The land was added to the Wupatki National Monument by Public Law 87–136, and the revocation is needed to clarify the records and give the National Park Service total jurisdiction. The land has been and will remain closed to surface entry and mining. This is a record clearing action only.

EFFECTIVE DATE: April 13, 1995.

FOR FURTHER INFORMATION CONTACT: John Mezes, BLM Arizona State Office, P.O. Box 16563, Phoenix, Arizona 85011, 602–650–0509.

By virtue of the authority vested in the Secretary of the Interior by Section 204 of the Federal Land Policy and Management Act of 1976, 43 U.S.C. 1714 (1988), it is ordered as follows:

1. Public Land Order No. 1076, which withdrew the following described public land, is hereby revoked in its entirety:

Gila and Salt River Meridian

T. 25 N., R. 8 E.,

Sec. 3, W½, that part lying west of the west right-of-way line of U.S. Highway 89 (consisting of lot 4, SW¼NW¼, NW¼SW¼, part of the westerly portions of lot 3, SE¼NW¼, and E½SW¼)

The area described contains 240 acres in Coconino County.

2. The land is located within the Wupatki National Monument and will remain closed to surface entry and mining.

Dated: April 4, 1995.

Bob Armstrong,

Assistant Secretary of the Interior.

[FR Doc. 95–9098 Filed 4–12–95; 8:45 am]

BILLING CODE 4310–32–P

43 CFR Public Land Order 7133

[OR–943–1430–01; GP5–038; OR–50706(WA)]

Withdrawal of National Forest System Lands for Five Seed Orchards; Washington

AGENCY: Bureau of Land Management, Interior.

ACTION: Public land order.

SUMMARY: This order withdraws 496.22 acres of National Forest System lands in the Colville and Kaniksu National Forests from mining for a period of 20 years for the Department of Agriculture, Forest Service, to protect the Brown

Mountain Seed Orchard, Pal Moore Meadows Seed Orchard, Teepee Seed Orchard, Cedar Creek Seed Orchard, and Flowery Trail Seed Orchard. The lands have been and will remain open to such forms of disposition as may by law be made of National Forest System lands and to mineral leasing.

EFFECTIVE DATE: April 13, 1995.

FOR FURTHER INFORMATION CONTACT: Linda Sullivan, BLM Oregon/Washington State Office, P.O. Box 2965, Portland, Oregon 97208–2965, 503–280–7171.

By virtue of the authority vested in the Secretary of the Interior by Section 204 of the Federal Land Policy and Management Act of 1976, 43 U.S.C. 1714 (1988), it is ordered as follows:

1. Subject to valid existing rights, the following described National Forest System lands are hereby withdrawn from location and entry under the United States mining laws (30 U.S.C. Ch. 2 (1988)), but not from leasing under the mineral leasing laws, to protect the investment in five Forest Service seed orchards:

Willamette Meridian

Colville National Forest

Brown Mountain Seed Orchard

T. 35 N., R. 33 E.,
Sec. 16, NW¼NW¼ and N½SW¼NW¼;
Sec. 17, E½E½NE¼NE¼ and E½NE¼SE¼NE¼.

Pal Moore Meadows Seed Orchard

T. 33 N., R. 41 E.,
Sec. 1, W½E½ and W½ of lot 4 and W½SW¼NW¼;
Sec. 2, S½S½ of lot 1, S½SE¼ of lot 2, and S½NE¼.

Teepee Seed Orchard

T. 37 N., R. 42 E.,
Sec. 34, S½SE¼NW¼NE¼, E½SW¼NE¼, W½SE¼NE¼, N½NW¼NE¼SE¼, and N½NE¼NW¼SE¼.

Cedar Creek Seed Orchard

T. 40 N., R. 42 E.,
Sec. 10, SE¼NE¼SW¼, W½E½SW¼, W½SW¼, and NE¼SE¼SW¼.

Kaniksu National Forest

Flowery Trail Seed Orchard

T. 32 N., R. 43 E.,
Sec. 5, S½NE¼SW¼, E½SW¼SW¼, and SE¼SW¼.

The areas described aggregate 496.22 acres in Ferry, Stevens, and Pend Oreille Counties.

2. The withdrawal made by this order does not alter the applicability of those public land laws governing the use of the National Forest System lands under lease, license, or permit, or governing the disposal of their mineral or vegetative resources other than under the mining laws.

3. This withdrawal will expire 20 years from the effective date of this order unless, as a result of a review conducted before the expiration date pursuant to Section 204(f) of the Federal Land Policy and Management Act of 1976, 43 U.S.C. 1714(f) (1988), the Secretary determines that the withdrawal shall be extended.

Dated: April 4, 1995.

Bob Armstrong,

Assistant Secretary of the Interior.

[FR Doc. 95–9099 Filed 4–12–95; 8:45 am]

BILLING CODE 4310–33–P

43 CFR Public Land Order 7137

[CO–930–1920–00–4357; COC–52206]

Transfer of Public Land for the Maybell Disposal Site; Colorado

AGENCY: Bureau of Land Management, Interior.

ACTION: Public land order.

SUMMARY: This order permanently transfers 140.49 acres of public land to the Department of Energy in accordance with the terms of the Uranium Mill Tailings Radiation Control Act of 1978 (42 U.S.C. 7916 (1988)), as amended.

EFFECTIVE DATE: April 13, 1995.

FOR FURTHER INFORMATION CONTACT: Doris E. Chelius, BLM Colorado State Office, 2850 Youngfield Street, Lakewood, Colorado 80215–7076, 303–239–3706.

By virtue of the authority vested in the Secretary of the Interior by the Uranium Mill Tailings Radiation Control Act of 1978 (42 U.S.C. 7916 (1988)), as amended, it is ordered as follows:

1. Subject to valid existing rights, the following described public land is hereby permanently transferred to the Department of Energy, and as a result of this transfer, the land is no longer subject to the operation of the general land laws, including the mining and the mineral leasing laws, for the Maybell Disposal Site:

Sixth Principal Meridian

T. 7 N., R. 94 W.,
Sec. 19, lots 10, 12, 14, and 16, W½E½SW¼NE¼, W½E½NE¼SW¼NE¼, W½SW¼NE¼, SE¼NW¼, W½W½NE¼NW¼SE¼, and W½NW¼SE¼.

The area described contains 140.49 acres of public land in Moffat County.

2. The transfer of the above-described land to the Department of Energy vests in that Department full management, jurisdiction, responsibility, and liability for such land and all activities conducted therein, except as provided in paragraph 3.

3. The Secretary of the Interior shall retain the authority to administer any existing claims, rights, and interests in this land established before the effective date of the transfer.

Dated: April 7, 1995.

Bob Armstrong,

Assistant Secretary of the Interior.

[FR Doc. 95–9048 Filed 4–12–95; 8:45 am]

BILLING CODE 4310–JB–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 2

[ET Docket No. 92–28; FCC 95–71]

Mobile-Satellite Service at 1610–1626.5 and 2483.5–2500 MHz

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This Second Report and Order denies five pioneer's preference requests submitted by Constellation Communications, Inc. (Constellation), Ellipsat Corporation (Ellipsat), Loral Qualcomm Satellite Services, Inc. (LQSS), Motorola Satellite Communications, Inc. (Motorola), and TRW Inc. (TRW). These parties requested a pioneer's preference for their proposals with regard to non-geostationary (low-Earth orbit, or LEO) mobile-satellite service (MSS) systems. In denying the requests, the Commission has determined that none of these LEO MSS proponents pioneered an innovative new service or technology.

EFFECTIVE DATE: May 15, 1995.

FOR FURTHER INFORMATION CONTACT: Ray LaForge, Office of Engineering and Technology, telephone (202) 739–0598.

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Memorandum Opinion and Order in ET Docket No. 92–28, adopted February 24, 1995 and released March 30, 1995. The complete text of this Memorandum Opinion and Order is available for inspection and copying during normal business hours in the FCC Public Reference Center (Room 239), 1919 M Street, NW, Washington, DC. The complete text of this Memorandum Opinion and Order also may be purchased from the Commission's duplication contractor, International Transcription Service, Inc., 2100 M Street, NW, Suite 140, Washington, DC 20036, (202) 857–3800.

Summary of Second Report and Order

1. In the Notice of Proposed Rule Making and Tentative Decision, ET Docket No. 92–28, 7 FCC Rcd 6414, 57 FR 43434 (September 21, 1992), in this proceeding, we decided not to award a pioneer's preference to any of the five applicants proposing to establish LEO MSS systems. We were unable to discern a significant innovation in any of the five proposals that would warrant a preference grant. In each case, the technology relied upon to show innovation appeared to have already been used on existing satellite systems. Further, we found that none of the five applicants demonstrated, at the time of filing of their applications for a pioneer's preference, the technical feasibility of their respective systems. As noted, the Second Report and Order affirmed the Tentative Decision with respect to each of the five applicants. The Commission reason for not awarding preferences to these applicants were as follows.

2. First, Constellation requests a pioneer's preference for its proposed LEO MSS system, stating that its proposal is innovative because it would use: (1) Micro-satellites that are designed as an outgrowth of other satellites that Constellation had pioneered for the U.S. military; (2) dynamic receivers; and (3) a new launch vehicle that enables satellites to be launched into orbit in a more cost-efficient and reliable manner. Constellation proposes a nationwide satellite service that would, *inter alia*, serve areas and people who do not currently have access to any telecommunications service.

3. In the Tentative Decision, we concluded that Constellation's proposal merely combined existing technologies and did not constitute innovative achievements. We also noted that Constellation had neither demonstrated that its micro-satellite and dynamic receiver are unique, nor provided a technical showing to demonstrate that its design surpassed the state-of-art in satellite communications technology. Thus, we concluded that Constellation did not warrant a preference. No commenting party addressed the tentative denial of Constellation's request. Accordingly, in the Second R&O, we find no basis in the record to indicate that an award of a pioneer's preference is warranted and therefore, deny Constellation's pioneer's preference request.

4. Second, Ellipsat asserts that it was the first applicant for a LEO system in these bands. Specifically, Ellipsat proposes to operate a nationwide mobile voice and position determination service via small low-Earth orbit satellites. Ellipsat requests a pioneer's preference for its alleged pioneering proposal for a voice and position determination LEO MSS system that: (1) Would be the first commercial use of elliptical orbits that optimize coverage over the U.S.; (2) would provide efficient spectrum use and facilitate sharing and multiple entry by other licensees by using code division multiple access (CDMA) spread spectrum technology; and (3) would utilize "transparent interconnections" between ground and satellite stations resulting in a seamless communications network which will provide low-cost, high-quality voice service. In addition, Ellipsat asserts that it was the first to apply for a LEO MSS system in the 1.6 and 2.4 GHz bands.

5. In the Tentative Decision, we concluded that Ellipsat failed to meet its burden of demonstrating that its proposal is new and innovative. We found that the techniques Ellipsat proposed to use already exist in the satellite community and thus do not demonstrate an innovative contribution. We stated that the elliptical orbits relied upon by Ellipsat to demonstrate innovation have been used by U.S. military satellites and the Russian Molnyia satellite system. Further, we found that Ellipsat had not demonstrated that it had pioneered the use of "transparent interconnections" between ground and satellite components or CDMA technology. Also, we found that Ellipsat did not have a significant lead over the other preference applicants in concept design nor had it performed relevant verifiable experiments. Thus, we stated that it would be inappropriate to single out Ellipsat for a preference based on the timing of its submissions.

6. In comments to the Tentative Decision, Ellipsat supports our decision not to award any pioneer's preferences in this proceeding. Ellipsat states that if any preferences are awarded, it warrants a grant since it was the first to propose a LEO satellite system above 1 GHz. Ellipsat did not submit additional information related to its own proposed system, and no other party commented on the tentative denial of Ellipsat's request. Accordingly, in the Second R&O, we find no basis in the record to indicate that an award of a pioneer's preference is warranted and, therefore, deny Ellipsat's pioneer's preference request.

7. Third, LQSS requests a pioneer's preference for its proposed enhanced satellite system that it states can provide data and voice transmission to hand-held portable transceivers and also provide position determination services. LQSS argues that its proposed system reflects substantial development of new system architecture and provides for multiple users and interoperability with the existing public telephone switched network. Further, it claims that its satellite system design using eight satellites per circular orbital plane, spot beams, smooth call hand-off, and a pilot channel for synchronization with gateway stations is innovative. Further, LQSS claims that is high system capacity accommodates thousands of voice and data users simultaneously. LQSS proposes to use CDMA spread spectrum technology that its Qualcomm subsidiary developed and patented. LQSS submits that all of these developments constitute innovations that satisfy the criteria for a pioneer's preference.

8. In the Tentative Decision, we found that LQSS's proposal offers no contribution to communications technology that is significantly innovative. No party commented on the tentative denial of LQSS's request. Accordingly, in the Second R&O, we find no basis in the record to indicate that an award of a pioneer's preference is warranted and, therefore, deny LQSS's pioneer's preference request.

9. Fourth, Motorola requests a pioneer's preference for its proposed LEO MSS system that it contends uses an innovative cellular design and spot beam technology. Motorola states that in the case of conventional cellular telephones, a static set of cells serves a large number of mobile units, whereas in its proposed system, cells would, in effect, move rapidly over the Earth while mobile units remain relatively stationary. Motorola claims that the unique elements of its system are its spectral efficiency and innovative design that includes the use of intersatellite links, a combination of frequency division multiple access and time division multiple access techniques, and bi-directional capabilities.

10. In the Tentative Decision, we concluded that Motorola's approach does not offer any significant improvements or innovations in service or technology. We found that Motorola's use of inter-satellite links and its concept of moving cells and spot beams have been utilized in earlier satellite systems and are thus not innovative. As we stated in the Tentative Decision, the U.S. military established inter-satellite link (crosslink) feasibility in 1976. Further, the technique of moving cells and spot beams has been utilized by the Department of Defense on its satellites

to improve coverage and provide frequency reuse. We also disagree that Motorola was the first to conceive and design a LEO satellite system above 1 GHz. From the record, it appears that all of the pioneer's preference applicants were performing research and developing their proposals in approximately the same time frame. Motorola's comments do not persuade us that the above findings were incorrect.

11. Further, we find that even if Motorola's system were innovative, it still would not meet our pioneer's preference criteria because Motorola did not demonstrate the technical feasibility of its proposed system prior to the Notice of Proposed Rule Making and Tentative Decision in this proceeding. Rather, the information submitted by Motorola at that time related to major spacecraft and ground segment systems and did not relate to the subsystem details necessary to establish technical feasibility.

12. Motorola also argues that we erred when we permitted a group of experts from other federal agencies to advise us on the merits of the requests without opening the results of this review to public comment. Motorola contends that this constituted peer review as contemplated by us when we established the pioneer's preference rules in Docket 90–217 (see Report and Order GEN Docket 90–217, 6 FCC Rcd 3488, 56 FR 24011 (May 28, 1991)) and that we should have released the results of the experts' evaluations to the public for comment. However, we disagree that the review performed by representatives of other government agencies constituted peer review. These representatives are employees from other federal government agencies who have expertise in satellite engineering matters. They were detailed by their agencies to the Commission and performed duties as Commission staff. The Commission brought these employees onboard using normal FCC personnel practices. Further, we follow this course of action routinely when we need additional resources or expertise in various matters. Here, the purpose of the work detail was to provide additional analysis by government experts of the pioneer's preference requests, but not to perform independent peer review as discussed in the Report and Order in Docket 90–217, (see Report and Order GEN Docket 90–217, 6 FCC Rcd 3488, 56 FR 24011 (May 28, 1991)). Therein, we contemplated soliciting assistance from either government or non-government experts who would not be functioning as Commission staff. Thus, there was nothing unfair in the Commission's use of employees on detail from other Government agencies to assist in the review of the various proposals. For all of these reasons, the Second R&O concludes that Motorola is not entitled to a pioneer's preference and that the procedure used to reach that decision was appropriate.

13. Finally, TRW requests a pioneer's preference for developing a LEO MSS system that would use higher orbits to provide position determination, voice communications, and data services to mobile users. It claims that its proposed service is a significant and innovative new use because the provision of co-primary mobile voice and data services is not currently authorized in the 1.6 and 2.4 GHz bands. TRW states that its system combines the advantages of LEO and geostationary orbit (GSO) systems by providing low communications time delay compared to the delay associated with GSO systems, while using higher elevation angles than other LEO proponents to minimize obstruction by trees, buildings, and terrain. Finally, TRW states that its proposed system will provide inexpensive service to underserved segments of society, including emergency service providers, farmers, ranchers, truckers, and automobile, sea, and air travelers.

14. In the Tentative Decision, we concluded that although TRW's LEO system would take advantage of higher orbits, its proposal was not sufficiently innovative to warrant a preference. We found that TRW merely had balanced the relative advantages and disadvantages of LEO versus GSO systems.

15. In comments to the Tentative Decision, TRW states that we pursued the most prudent and reasonable course in declining to award any of the applicants a preference. No other party commented on the proposed denial of TRW's request. Accordingly, in the Second R&O, we find no basis in the record to indicate that an award of a pioneer's preference is warranted and, therefore, deny TRW's pioneer's preference request.

16. Accordingly, it is ordered, That the pioneer's preference requests filed by Constellation Communications, Inc., Ellipsat Corporation, Loral Qualcomm Satellite Services, Inc., Motorola Satellite Communications, Inc., and TRW Inc. are denied. This action is taken pursuant to sections 4(i), 303 (c), (f), (g), and (r) of the Communications Act of 1934, as amended, 47 U.S.C. sections 154(i), 303 (c), (f), (g), and (r).

List of Subjects in 47 CFR Part 2

Radio.

Federal Communications Commission.

William F. Caton,

Acting Secretary.

[FR Doc. 95–9092 Filed 4–12–95; 8:45 am]

BILLING CODE 6712–01–M

federal register

Tuesday
April 4, 1995

Part II

Environmental Protection Agency

40 CFR Part 9, et al.

Opting into the Acid Rain Program; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9, 72, 73, 74, 75, 77 and 78

[FRL–5178–5]

RIN 2060–AD43

Opting Into the Acid Rain Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Under title IV of the Clean Air Act, Congress authorized the U.S. Environmental Protection Agency (EPA) to establish the Acid Rain Program. The principal goal of the program is to achieve significant environmental benefits through reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions, the primary components of acid rain. Acid rain causes surface water acidification, damages trees at high elevations and accelerates the decay of building materials. In addition, air concentrations of SO_2 and NO_X degrade visibility in large parts of the country and acidic aerosols derived from these emissions may pose a risk to public health.

The Acid Rain Program departs from traditional regulatory methods by introducing an SO_2 allowance trading system that lowers the cost of reducing emissions by allowing electric utilities as a group to seek out the least costly methods of control. Utility units affected under title IV are allocated allowances based on their historic emissions and these units may trade allowances, provided that at the end of each year, each unit holds enough allowances to cover its annual SO_2 emissions.

Today's action establishes an additional component to the Acid Rain Program called the Opt-in Program. The Opt-in Program allows sources not required to participate in the Acid Rain Program the opportunity to participate on a voluntary basis. Such sources, known as combustion sources, would include small utility units and industrial boilers. These rules detail how combustion sources participate in the allowance market by "opting in" to the Acid Rain Program, as provided under section 410 of the Act. Congress envisioned the Opt-in Program as a means of generating additional allowances and through which the compliance costs of acid rain control in the utility sector could be reduced, while still meeting overall emissions reductions goals.

EFFECTIVE DATE: These rules become effective on May 4, 1995.

ADDRESSES: *Docket*. Docket No. A–93–15, containing information considered during development of the promulgated rule, is available for public inspection and copying between 8 a.m. and 5:30 p.m., Monday through Friday, at EPA's Air Docket Section (6102), Waterside Mall, room M1500, 1st Floor, 401 M Street SW., Washington, DC 20460. A reasonable fee may be charged for copying.

Background information document. The background information document containing responses to public comments on the proposed standards may be obtained from the docket. Please refer to "Final Opt-in Rule for Combustion Sources—Comment Response Document."

FOR FURTHER INFORMATION CONTACT: Acid Rain Hotline (202) 233–9620 or Adam Klinger (202) 233–9122, Acid Rain Division; mailing address, U.S. EPA, Acid Rain Division (6204J), 401 M Street, SW., Washington, DC 20460.

SUPPLEMENTARY INFORMATION: The contents of this preamble are as follows:

A. Background and Summary

1. Background

Acid deposition occurs when emissions of sulfur dioxide and oxides of nitrogen are chemically transformed in the atmosphere into sulfuric and nitric acids and return to earth as wet deposition such as rain, fog, or snow, or dry deposition such as fine particles or gases. Acid deposition damages lakes and harms forests and buildings. SO_2 emissions damage ecosystems and materials, contribute to reduced visibility and, at current levels, are suspected of posing a threat to human health.

Title IV of the Clean Air Act, as amended by the Clean Air Act Amendments of 1990, directs EPA to establish the Acid Rain Program to reduce the adverse effects of acidic deposition. Title IV targets the electric utility industry, which accounts for over two-thirds of SO_2 emissions and over one-third of NO_X emissions in the United States. Specifically, the Act mandates a national cap of 8.95 million tons per year on electric utility SO_2 emissions by the year 2010 (just over half of the 1980 electric utility SO_2 emissions), to be achieved in two phases. Phase I will begin in 1995 and mainly affects large, high-emitting utility plants; these plants are specifically listed in the statute. Phase II will begin in 2000 and affects virtually all existing utility units with output capacity greater than 25 megawatts and most new utility units.

The centerpiece of the Acid Rain Program is a unique trading system in which allowances are bought and sold at prices determined in the marketplace. Each allowance authorizes the emission of up to one ton of SO_2 during or after a designated year. The majority of utility units—both existing and some new units—are allocated allowances based on their historic fuel use and the emissions limitations specified in the Act. Utility units are required to limit SO_2 emissions to the number of allowances they hold, but since allowances are fully transferrable, utilities may meet their emissions control requirements in the most cost-effective manner possible. For instance, a utility may decide to (1) switch to a lower sulfur fuel, (2) install flue gas desulfurization equipment (scrubbers) and bank unused allowances or sell them to other utilities/individuals, (3) forego emissions reductions and buy additional allowances (if necessary), or (4) implement energy efficiency measures. Other options and combinations of options are possible, providing an unusually high degree of flexibility for affected units to comply with the law. The procedures for transferring and tracking allowances are codified in 40 CFR part 73.

Each affected unit must have a permit in which the affected unit certifies that it will possess a sufficient number of allowances to cover its SO_2 emissions and specifies the source's compliance options. The permit regulation is codified in 40 CFR part 72.

To ensure that nationally mandated reductions in SO_2 and NO_X emissions are achieved, each affected unit must in[illegible]uous emissions monitoring system and collect, record, and report emissions data. The continuous emissions monitoring rule is codified in 40 CFR part 75.

If an affected unit violates the Act by emitting more emissions than the allowances it holds, the Act requires that the affected unit pay penalties and submit a plan detailing how and when the excess SO_2 emissions will be offset. These requirements act as a strong incentive for compliance with the mandated emissions reductions of the Acid Rain Program. Excess emissions penalty requirements are codified in 40 CFR part 77.

Finally, 40 CFR part 78 contains administrative appeals procedures for resolving disputes over decisions by the Administrator regarding any aspect of the Acid Rain Program.

2. The Opt-in Program

Although the Acid Rain Program is mandated only for utility sources, section 410 provides opportunities for SO_2-emitting sources not otherwise affected by title IV requirements (e.g., industrial sources) to participate in the Acid Rain Program by "opting in."

The Opt-in Program is a voluntary economic incentive provision. Congress developed the Opt-in Program to reduce further the cost of complying with the Acid Rain Program. Combustion or process sources not otherwise required to reduce SO_2 emissions can opt in and make incremental, lower-cost reductions. Congress envisioned section 410 as a means of generating additional allowances to reduce compliance costs for affected utilities and to encourage combustion or process sources to consider cost-effective emission reduction opportunities:

> [Section 410] adds flexibility and can enlarge the universe of sources for which there are cost-effective reductions in emissions of SO_2 * * *. This section provides a useful additional source of reductions that can be made voluntarily by sources choosing to be affected by the provisions of this title. (Senate Committee Report, Report No. 101–228, December 20, 1989, p. 335.)

The reductions—in the form of acid rain allowances—can be transferred to meet mandatory reduction requirements in the utility sector and, thus, lower the overall cost of the Acid Rain Program. However, Congress also intended that this shifting of SO_2 emissions between opt-in sources and affected utility units not compromise the overall title IV SO_2 emissions reduction goals. Section 410 "is intended to further the objective of achieving true net reductions of SO_2 * * *." (*Id.* at 336.) The Opt-in Program has been designed to take advantage of lower cost reduction opportunities at non-affected sources consistent with the statutory requirements of section 410 of the Act and emissions reductions goals (i.e., the required 10 million ton reduction of SO_2) of title IV.

3. Summary of Final Rule

The final opt-in regulation for combustion sources details the process through which combustion sources can enter the Opt-in Program and the requirements they face while participating. The rule allows any stationary fossil fuel fired combustion device, i.e., any combustion source, to become an affected unit and receive allowances. This rule focuses on combustion sources. The treatment of process sources and specifically the application and monitoring requirements for process sources will be addressed in a subsequent rulemaking. The permitting process finalized in today's rule does pertain to both combustion and process sources.

Allowance allocations for opt-in sources, as for utility units, are based on operations during 1985, 1986, and 1987. Like utilities in the mandatory program, once a combustion source opts in, it must hold allowances to cover its emissions. Presumably, the opt-in source will reduce its emissions from its baseline level to generate excess allowances to sell to other affected units. Because opting in is voluntary, only combustion sources that would profit by selling excess allowances are expected to participate in the program. In addition, since all affected sources must also comply with the other applicable requirements of the Act, revenue generated by selling excess allowances could help opt-in sources to offset costs of compliance with other programs.

Although EPA has attempted to treat opt-in sources comparably to utility units in the mandatory Acid Rain Program, there are some situations where restrictions on opt-in sources are needed to protect the emission goals of the Act. In section 410(f), Congress expressly prohibits opt-in sources from transferring allowances that result when they reduce utilization or shut down. Without this prohibition, an individual opt-in source could increase overall emissions by shifting some or all of its production from the opt-in source to new or existing non-affected sources, accumulating the opt-in source's unused allowances, and then selling them to other affected sources.

In order to ensure the surrender of allowances in cases of reduced utilization and shutdown, EPA reserves the right to cancel allowances produced by reduced utilization or shutdown by removing them from any Allowance Tracking System (ATS) accounts into which they had been transferred. To facilitate this prospect of cancellation and to protect buyers of opt-in allowances, EPA is restricting the transfer of future year allowances. In the final rule, EPA continues to allocate allowances, in perpetuity, upon application, but is prohibiting the transfer of future year allowances from opt-in unit accounts in the ATS; only current year or earlier allowances can be transferred. This policy will eliminate the need to cancel future year allowances in cases where a unit shuts down and sells all its future year allowances. Trades involving future year allowances can still be made; however, delivery of future year allowances to the buyer must wait until the year for which those allowances are to be used for compliance.

Title IV contains one exception to the overall restriction on opt-in allowances generated by reduced utilization and shutdown. When a "replacement unit" replaces thermal energy formerly supplied by an opt-in source, then the opt-in source may transfer allowances to the replacement unit to the extent of that replacement, despite the reduction of utilization at the opt-in source. For purposes of this thermal energy exception, EPA defines thermal energy to be steam used in an industrial process, as distinct from steam used to generate electricity, and bases the calculation of transferable allowances on the fuel associated with the thermal energy and the allowable emissions rate at the replacement unit.

Eligible combustion sources may submit applications to EPA, as the permitting authority in the near term, and to a State or local permitting authority, once that permitting authority has an Opt-in Program in place under part 70. Upon receipt of the application, its evaluation proceeds on two parallel paths will commence: (1) The procedure for processing an opt-in permit; and (2) the procedure for evaluating the opt-in source's monitoring plan and certifying its monitoring systems. After both of these procedures have been successfully completed, the combustion source may enter the Opt-in Program.

B. Major Changes Made to the Proposed Rule

Although considerable changes have been made to the language and structure of the proposed opt-in regulation for combustion sources, the essential elements of the program remain unchanged and the final rule is consistent with the regulatory goals discussed in the proposed rule, which the Agency here reaffirms. The bulk of this preamble details the major changes that have been made:

1. Acceptable Data Sources

EPA continues to believe that there is no single reliable data base that would provide the Agency with quality information on operations and emissions of potential opt-in sources. Therefore, the Agency must rely on information supplied by the combustion source in an application process. In § 74.20(a)(2) of the proposed rule, EPA established a screen for ensuring that reliable data is submitted to the Agency, by requiring all data to have been previously submitted to a government agency.

Today's rule does not require the previous submission of data to a government agency as a precondition for combustion sources to apply to enter the Opt-in Program. Instead, EPA will conduct its own evaluation of the data submitted for the Opt-in Program using its best judgment, although the burden of proof regarding the data's accuracy will remain with the applying combustion source. Regardless of whether a state permitting program is in place and whether the State or EPA is the permitting authority, EPA will retain this data review authority consistent with its responsibility for all allowance-related activities, as discussed in the preamble to the proposed rule.

EPA will lead an evaluation process that brings in the expertise of state officials as well as other technical data experts. EPA will retain the authority, consistent with § 72.4 of part 72, to request any additional documentation, in addition to the formal opt-in permit application, that it believes is necessary to evaluate the combustion source's data. Previous submittals to government agencies that are in existence will be expected to accompany the application. In addition, EPA may request data for years outside the baseline period, both before and after, to verify that submitted baseline data does not represent an inexplicable spike in the combustion source's operations. EPA may also request additional supporting documentation (e.g., fuel purchasing records, production rates, throughputs, sampling protocols, etc.) that the Agency believes necessary to verify the information contained in the combustion source's opt-in permit application. EPA may, in addition, make inspections and examine records at the combustion source applying to enter the Opt-in Program.

Opt-in permit applications submitted by combustion sources with entries in the National Allowance Data Base (NADB) will still face scrutiny, and the data values within the NADB will not be accepted automatically. Such scrutiny and potential revisions are consistent with previous Agency assertions that the NADB version 2.11 was the final version to be used in the development of allocations for Phase II units (see 57 FR 30034 and 58 FR 15721). Combustion sources, by definition, cannot be Phase II units and were not automatically allocated allowances under section 405 of the Act. Therefore, the NADB data for these sources have not been reviewed by EPA to the same extent as Phase II unit data, and such review has not been precluded by previous regulatory actions.

The evaluation of data by EPA for the purposes of calculating allowances is not unprecedented. In developing Phase II unit data in the NADB, EPA compiled information from a number of sources that included the Energy Information Administration (EIA), the North American Electric Reliability Council (NERC), the affected sources, and, to a lesser extent, states. EPA expects the states to play a larger role in evaluating industrial operating and emissions data, because the states are often the best repository of such information and are aware of the detailed operations of such sources.

Both the applying combustion source and third parties will have access to and be able to assess the information EPA ultimately accepts in its allowance calculation. Both the combustion source and third parties will be able to scrutinize the baseline data and the number of allocated allowances during the public comment period associated with the draft opt-in permit. Furthermore, the combustion source has the opportunity to decline to opt in at any time prior to the effective date of the opt-in permit. The combustion source can also appeal its allowance allocation consistent with the procedures prescribed in part 78.

While the information for industrial opt-in sources will be less readily available, EPA sees no other workable alternative than to assume the responsibility of examining submitted data on a case-by-case basis. The Agency recognizes that some incentives will remain for the combustion source to overstate its baseline for the purposes of increasing its allowance allocation, but believes that such risks will be offset by Agency review of the data and supporting documents, the rejection of insufficiently supported data, and the threat of enforcement actions and penalties for falsely submitted data. Toward these ends, EPA will enhance the certification statements that designated representatives sign when submitting an opt-in permit application to assure that such submittals (1) are believed to be true, accurate, and complete; (2) are accompanied by all available documentation that the combustion source and its state regulatory agencies possess that are relevant to the accuracy of such data; and (3) are not adjusted in any way.

2. Allocation of Opt-in Allowances and Transfer Prohibition

In the proposed rule, EPA planned to allocate allowances on a one-time, in perpetuity basis and allowed for the transfer of current and future-year opt-in allowances from opt-in accounts into other accounts in the Allowance Tracking System (ATS). This policy was proposed to promote fungibility of opt-in allowances and provide combustion sources flexibility in their compliance planning. However, in order to uphold the requirements of section 410(f) of the Act, EPA also proposed in § 74.50 of the proposed rule to reserve the right to cancel, under certain circumstances, any allowances that were initially allocated to an opt-in source by removing allowances from any ATS accounts into which they had been transferred.

Under section 410(f), the Act restricts opt-in sources from transferring or banking allowances produced as a result of reduced utilization or shutdown, except as discussed in the proposed rule (58 FR 50103) and later in this preamble under the thermal energy exception. To uphold this restriction, EPA is requiring opt-in sources to surrender allowances generated by reduced utilization or shutdown. In the proposed rule, EPA maintained that in the case where an opt-in source has shut down, reduced its utilization or has excess emissions, *and* fails to supply the equivalent number of allowances owed to EPA (presumably because the opt-in source has sold all of its future-year allowances), EPA must recover and cancel the opt-in source's allowances in the required number from other ATS accounts into which they were transferred. Canceling opt-in allowances held in other accounts in the ATS was considered the only way to ensure that such allowances did not result in additional emissions and that the SO_2 emissions reduction goals of the Acid Rain Program were preserved. EPA maintained in the proposed rule that the allowance market would account for the risk of cancellation by asking lower prices for opt-in allowances and writing protective clauses into sales contracts.

In the final rule, EPA is choosing to allocate allowances, in perpetuity, at the time the combustion source becomes an affected unit, but, based on the comments received, is prohibiting the transfer of future-year opt-in allowances from opt-in source accounts in the Allowance Tracking System (ATS). Transfers of current-year opt-in allowances will only be recorded by EPA following the completion of the end-of-year reconciliation process for the previous compliance year, as set forth in § 73.34(a) of 40 CFR part 73. If an opt-in source is found to have excess emissions for a given year, that opt-in source will be prohibited from transferring the following year's allowances until an offset plan is approved and allowances have been deducted to offset its excess emissions.

When an opt-in source permanently shuts down, it may no longer retain allocated allowances and must surrender to EPA all of its opt-in allowances starting with the year in which the opt-in source shuts down. In the case of an opt-in source that has shut down, as opposed to an opt-in source that is still operating, EPA cannot draw upon future-year allowances to offset excess emissions because such allowances have already been surrendered. Therefore, EPA reserves the right to cancel opt-in allowances (specifically, allowances for the year for which the opt-in source has excess emissions and the year in which the opt-in source shuts down) from any ATS account into which such allowances have been transferred. Previous year opt-in allowances that had subsequently been transferred to other ATS accounts would not be canceled because such allowances were in excess of the number of allowances needed for compliance in previous years.

EPA retains the option of allowance cancellation to ensure that opt-in sources through their operations cannot increase emissions to the environment. EPA believes that the Opt-in Program must be self-enforcing and should not rely on possible future regulation to implement the 5.6 million ton cap for industrial sources because of the reasons discussed in the proposed rule: (1) The incomplete coverage of the Opt-in Program relative to the industrial sector; (2) the importance of achieving title IV emission reduction goals by maintaining the emissions neutrality of the Opt-in Program relative to historic emission levels (rather than future emission inventory levels); and (3) the aggregate nature of emission inventories and their lack of specificity to address emissions and allowance allocations of individual opt-in sources.

Furthermore, EPA agrees with commenters who believe that most trades of future-year opt-in allowances will take the form of "option contracts," e.g., the buyer and seller arrange today for the option to buy allowances at a future time at a quantity, price, and date set today. Buyers are more likely to enter into options contracts for future-year opt-in allowances because, if allowances are canceled, the buyer only loses the option to buy allowances and not the allowances themselves, as would be the case with other types of contracts. If these commenters are correct, then EPA's prohibition of the transfer of future-year opt-in allowances should not significantly alter expected market behavior and its treatment of opt-in allowances. In fact, current allowance market behavior in the utility sector suggests that, in many cases, a portion of the full price is paid now for future-year allowances, but the actual transfer of such allowances and payment of the remaining purchase price will not occur until the allowances become usable for compliance. Buyers are reluctant to pay full price now for allowances that cannot be used until a future date.

Although EPA is restricting the transfer of future-year opt-in allowances, it is allowing the transfer of current-year opt-in allowances as soon as the end-of-year reconciliation process for the previous year is completed. (EPA will allow, for the first current year, the transfer of current-year opt-in allowances upon entry into the Opt-in Program). EPA believes that current-year opt-in allowances may play a valuable role in assisting with compliance for the utility sector and must be available for transfer before the end of the current year. However, in order to uphold the requirements of section 410(f) of the Act, EPA reserves the right to cancel current-year opt-in allowances that have been allocated to the opt-in source in the event that an opt-in source has excess emissions and has shut down, been reconstructed, or become affected under § 72.6. EPA believes that restricting opt-in allowance transfers to current-year allowances will reduce the likelihood of having to cancel purchased opt-in allowances. Buyers of current-year opt-in allowances have a much better chance of accurately assessing the integrity, financial health, and future status of an opt-in source in a short time frame (i.e., within the current year) than they would in making an accurate assessment over a longer time frame (i.e., one extending as long as 31 years into the future). EPA considered not canceling current-year allowances, but instead using enforcement actions to try to recover excess opt-in allowances. EPA rejected this approach because of the concern that if enforcement actions were unsuccessful in the recovery of excess opt-in allowances, the clear direction of section 410(f) of the Act would be violated, and the emission reduction goals of title IV would be compromised.

3. Offering Opt-in Allowances on the Acid Rain Auction

In the proposed rule, EPA prohibited the trading of opt-in allowances in the Acid Rain auction. EPA is allowing, in the final rule, the offering of opt-in allowances in the spot auction, provided the compliance use date of the allowances offered is for a prior year. Prior year allowances are allowances dated a year or more prior to the spot auction year. Prior year opt-in allowances will have cleared the end-of-year compliance process including any possible allowance cancellations for reduced utilization, as discussed above. EPA is still prohibiting the submission of offers of current-year opt-in allowances in the Acid Rain auctions because these allowances have a possibility of being canceled by EPA in the future. Buyers of current-year opt-in allowances sold in the auctions have no protection against cancellation as they would if purchasing opt-in allowances through a private contract. EPA believes that if there is demand for an auction that includes current-year opt-in allowances, the private sector will develop such an outlet.

4. Thermal Energy Exception

Section 410(f) limits the transfer of opt-in allowances when opt-in sources reduce utilization or shutdown except when the reduced utilization or shutdown results from the replacement of thermal energy. EPA received numerous comments on implementing this thermal energy exception. This section discusses the three main issues associated with the thermal energy exception:

(a) The definition of thermal energy;

(b) The calculation of transferrable allowances; and

(c) The methodology used to calculate the fuel associated with thermal energy.

a. Definition of Thermal Energy

In § 72.2 of the proposed rule, EPA defined thermal energy as the thermal output produced by a combustion source used directly as part of a manufacturing process but not used to produce electricity. EPA received 29 comments on the definition of thermal energy.

Seventeen commenters disagreed with the proposed definition and argued that the thermal energy definition should include electrical output in addition to steam output. Several commenters argued that EPA has no statutory basis in section 410(f) to define thermal energy to include only steam output because the statute does not specifically cite the Public Utility Regulatory Policies Act (PURPA) definition of thermal energy used by the Agency in the proposed rule. Commenters also maintained that the legislative history does not support a limited definition. Lastly, commenters pointed out that because section 410(f) refers to the term "unit" that by definition does not distinguish between facilities that produce steam for generating electrical energy and those that produce steam for direct sale, the definition of thermal energy should not make such a distinction.

One commenter argued that thermal energy means "heat" and that the facilities affected by the Act are combustion units that produce heat, which sometimes is used to drive a turbine to create electricity and sometimes is used to create steam. Several other commenters noted that the proposed definition fails to take into account the integrated nature of many industrial facilities and does not consider how difficult it may be to determine how the thermal energy is allocated between steam and electricity.

In addition, a number of commenters believed that in developing the thermal energy definition, EPA ignored the intent of Congress to allow small electric generating units the opportunity to opt in, retire their older units, and transfer allowances to replacement sources.

Four commenters stated that EPA's proposed opt-in rule is inconsistent with the views stated in the "Dover Letter," sent to SFT, Inc. on March 7, 1991. The commenters contended that a representative from EPA's Office of Atmospheric and Indoor Air Programs stated that the City of Dover would be allowed to opt in its exempt boilers used to generate electricity under section 410 of title IV and then transfer the allowances received to a new, replacement boiler. The commenters argued that EPA should uphold its original views and allow electric units to opt in. One commenter, however, recognized that this "Dover Letter" was not a legally enforceable, binding statement of law.

Three commenters supported EPA's definition of thermal energy based on the argument that if electricity is included in the definition, the total number of permanent allowances and associated emissions would increase above what is permitted under title IV. These commenters also argue that the Act draws a clear distinction between thermal energy and the energy used for the generation of electric power and thus, small electricity generators should not be considered beneficiaries of the thermal replacement energy exemption.

Response: As stated in the preamble to the proposed rule (58 FR 50087), EPA believes defining thermal energy as the steam output used directly as part of a manufacturing process but not used to produce electricity is consistent with the Congressional intent and goals of title IV and section 410. For the reasons set forth in the preamble to the proposed rule, the final rule retains the definition of thermal energy as proposed and limits thermal energy to the steam output used directly in a manufacturing process but not used to produce electricity.

EPA continues to believe that Congress selected the term thermal energy precisely to distinguish between electric energy and thermal energy used in manufacturing processes. If Congress had intended thermal energy to mean total energy, which includes electricity, then it would have had no need to use the term "thermal" at all. Furthermore, EPA disagrees with those commenters who claimed that because Congress did not specifically cite the PURPA definition of thermal energy in title IV it is inappropriate to use that definition. With no definition specifically provided in the statute, limited legislative history, and no evidence that Congress intended otherwise, EPA believes that using the PURPA definition is appropriate since it provides a long standing, accepted meaning of the term within the federal regulatory framework governing industrial steam production and electrical generation.

Some commenters argued that because section 410(f) uses the term "unit", Congress did not intend to distinguish between sources that produce steam for generating electricity and those that produce steam for direct sale. However, EPA believes that the term "unit" as used in section 410(f) provides no basis for defining "thermal energy", but rather the term "unit" is used in section 410(f) only to limit the transfer of allowances under the thermal energy exception to affected units (i.e., "any other unit or units subject to the requirements of this title.")

EPA stated in the so called "Dover Letter" that its response to the City of Dover was based on preliminary assessments of the language in title IV and was subject to modification in the final EPA regulations:

> Below are EPA's comments based on the language in Title IV of the Act. You should be aware, however, that the views expressed in this letter are based on our preliminary assessments and could be modified in the final EPA regulations. (March 7, 1991 letter from Eileen Claussen to Tom Fitzpatrick).

By its own terms, the March 7, 1991 letter did not provide guidance, much less a statutory interpretation or an applicability determination for the units in question, that could be relied upon. In fact, the March 7, 1991 letter indicated that this was a preliminary views based only on the statutory language itself and did not indicate that any other material relevant to statutory interpretation (such as legislative history) had been considered. Several months thereafter, EPA sent a retraction letter on January 7, 1992 to the City of Dover reiterating that EPA's response in the March 7, 1991 letter was preliminary and that the Agency was reconsidering the legal and analytic basis of the position it had taken in the March 7, 1991 letter.

Lastly, EPA recognizes the integrated nature of some industrial cogeneration facilities but maintains, as confirmed by historic industrial reporting, that steam and electrical outputs are observable and measurable quantities.

b. Emission Rate Used To Calculate Transferable Allowances

To calculate the number of allowances that can be transferred from the opt-in source to a replacement unit under the thermal energy exception, EPA proposed, under § 74.47(b)(4), to use the lesser of the federally enforceable allowable emission rate at the replacement unit or 1.2 lbs/mmBtu. EPA received eighteen comments on this issue with no commenters supporting the 1.2 lbs/mmBtu emission rate cap as proposed, and six commenters supporting the use of the replacement unit's emission rate. Two commenters contended that the proposed 1.2 lbs/mmBtu emission rate is excessively high given that emission rates at replacement units are likely to be much lower.

Fifteen commenters objected to EPA's proposal of a 1.2 lbs/mmBtu emission rate limit as too restrictive. These commenters argued that the use of the 1.2 lbs/mmBtu emission rate is arbitrary and not supported by the statute where the replacement unit's emission rate is higher. They also pointed out that the proposed restriction does not recognize all possible replacement units (e.g., existing units) and would unjustifiably restrict allowance transfer during Phase I when the emission rate could be 2.5 lbs/mmBtu.

Response: After further consideration, EPA is eliminating the 1.2 lbs/mmBtu emission rate restriction used to calculate the number of allowances that can be transferred to the replacement unit under the thermal energy exception. Today's rule uses the federally enforceable emission rate at the replacement unit to calculate the number of transferable allowances.

The rule was changed because EPA agrees with the comments that the use of the 1.2 lbs/mmBtu does not recognize the different emission rates at potential replacement units, some of which may be existing units. In the preamble to the proposed rule, EPA argued that applying a 1.2 lbs/mmBtu rate is consistent with the requirements for Phase II units. However, since a replacement unit can be any affected unit, the universe of replacement units would include Phase I units with 2.5 lbs/mmBtu rates and other opt-in sources with emission rates that could be even higher. Given that these potential replacement units could have higher rates and that the statute does not set a limit for the emission rate, EPA believes there is no basis for restricting the emission rate to 1.2 lbs/mmBtu.

c. Methodology Revision for Calculating the Fuel Associated with Thermal Energy

In § 74.47(b) of the proposed rule, EPA required that replacement units calculate the fuel associated with thermal energy by dividing the amount of qualifying thermal energy (that is, the replacement thermal energy) by the efficiency associated with the production of thermal energy. EPA received several comments related to this issue.

One commenter suggested that all units of fuel used should be attributable to a unit's steam output because it is not practical to identify a thermal energy fuel increment (used to determine the allowance transfer) and because there is no established method for doing so.

Several commenters offered alternative formulas for calculating the transferable allowances. One suggested that EPA calculate the number of transferable allowances as the product of the "useful thermal energy output" of the replacement unit, as defined under PURPA, and the difference between the opt-in source's emission factor and the replacement unit's emission factor. This commenter contended that this will encourage more efficient cogeneration applications. Another suggested that EPA compute the number of transferable allowances by evaluating the portion of an opt-in source's historic thermal energy that is replaced by a cogeneration facility, rather than the portion of the cogeneration facility's energy output that is thermal energy. Other commenters recommended that EPA include provisions that provide an incentive to undertake energy efficiency gains at the replacement unit. The number of transferable allowances should be based on the replacement unit's emission rate taking into consideration any efficiency differences in steam production at the opt-in source and at the replacement unit.

Response: Based on the comments received, EPA is changing the methodology for calculating the fuel associated with qualifying thermal energy as discussed under § 74.47. In today's rule, EPA allows opt-in sources to use an efficiency constant when calculating fuel input from thermal output to give them an incentive to make their production processes more efficient.

EPA has chosen to make the calculation of transferred allowances based on a constant value rather than having replacement units calculate fuel utilization each year because relying on actual fuel utilization would discourage improvements in efficiency. By using a constant, a replacement unit that increases its efficiency will use less fuel to produce the same amount of thermal output, but will still have transferred to it the same number of allowances as before the efficiency improvement. In contrast, calculating the fuel utilization each year would reduce the incentives for efficiency improvements. This will be true for either boilers or cogenerators.

The efficiency constants selected represent the fuel utilization of the boiler or cogenerator supplying the replacement steam. Fuel utilization represents the quotient of all energy outputs and the energy content of total fuel input. The Agency distinguishes between boilers and cogenerators in establishing these constants to recognize the greater energy requirements necessary to produce electricity as opposed to producing steam. It would be unfair to compare the efficiency of cogenerators producing electricity and/or steam with the efficiency of boilers producing only steam, because the production of electricity inherently requires more fuel. In today's rule, the Agency sets the efficiency constant for boilers to be 0.85 and the efficiency constant for cogenerators to be 0.80. These constants represent industry averages for modern equipment (see memorandum in the docket entitled, "Evaluation of EPA's Revised Methodology for Calculating the Transferred Allowances under the Thermal Energy Exception").

For boilers serving as replacement units, the attribution of fuel associated with thermal energy is straightforward. However, for cogenerators, it is very difficult to distinguish between the fuel going towards steam or electricity, because the production of the two is tightly linked. Using fuel utilization implies that both the fuel input and the efficiency losses associated with the production of each product is proportional to the amount of each product produced.

EPA specifically defines thermal energy to consist of only steam and this definition does not include electricity (see previous discussion of thermal energy definition). In calculating allowances transferred under the thermal energy exception, EPA must distinguish between the fuel used to produce electricity and the fuel used to produce thermal output. The former does not count toward the thermal energy exception, while the latter does. Therefore, EPA does not believe it is appropriate or consistent with the statutory provisions in section 410(f) to attribute all fuel input to steam production, where, in fact, both steam and electricity are being produced.

EPA believes its revised methodology addresses the concerns of commenters seeking to instill incentives for cogeneration and specifically relying on the amount of thermal energy replaced. The alternative suggestion of basing allowance calculations on energy output is inconsistent with all other allowance calculations found in the Acid Rain Program. Allowances for utility units in the Acid Rain Program are generally calculated as a product of a fuel input baseline, expressed in mmBtu, and an emission rate, expressed in lbs. per mmBtu of fuel input. An allowance calculation where emission rates, reflecting energy input, are multiplied by the thermal energy replaced, reflecting energy output, would be internally inconsistent. The revised methodology, therefore, remains consistent with allowance calculations in the core utility program.

C. Other Significant Changes Made to the Proposed Rule

1. Ineligibility of Non-operating and Retired Units

EPA continues to require that combustion sources seeking to enter the Opt-in Program be operating at the time of application. Combustion sources opting in under the thermal energy exception are also required to be in operation, although they can shut down upon entry into the program.

EPA seeks to restrict the allocation and use of opt-in allowances to instances in which real emissions reductions will take place, and not to award allowances in situations of reduced utilization and shut down. EPA believes that this requirement to be operating at the time of application is consistent with this principle. The provision establishing such a requirement provides a clear criteria for assessing whether a combustion source has reduced its utilization or shut down (i.e. is not operating) for the purposes of accepting the combustion source into the program and allocating allowances.

In the final rule, EPA establishes a definition of operating strictly for the purposes of the Opt-in Program. Operating is defined to mean the documented consumption of fuel input for more than 876 hours in the 6 months immediately preceding application. This level of operating hours was selected because it serves as the upper bound of a peaking unit, that is, 20 percent capacity factor in any calendar year as defined in § 72.2. The Agency kept the 20 percent operating level, but shortened the period of time from one year to six months so that a combustion source could be idle at most approximately four and one half months, rather than twice that amount of time and still be eligible to opt in. EPA expects that combustion sources operating below the 20 percent level would have little interest in participating in the Opt-in Program because the number of allowances freed up from emission reductions would be small and unlikely to cover the costs of opt-in participation.

Whether or not they were operating at the time of application, combustion sources that operated in the 1985–1987 time period would have the necessary data to determine an allocation of opt-in allowances. However, a combustion source that was not operating at the time of application would have all or virtually all of its allowances deducted under the reduced utilization and shutdown provisions. EPA does not believe it is reasonable or administratively practical to grant these opt-in sources allowances and then, from the first year on, take virtually all of them away.

If a combustion source is shut down but plans to restart its operations, EPA believes that the combustion source should apply to opt in upon restart, that is where there is proof that the combustion source is now operating consistent with the above definition. Furthermore, the allowance allocation for opt-in sources that restart would be based on any current allowable SO_2 emissions rate in effect at the time of application.

As discussed under the thermal energy exception, non-operating opt-in sources may transfer allowances to replacement units, to the extent that such units can document the replacement of thermal energy. In allowing non-operating sources to participate in the thermal energy exception, but excluding non-operating sources from applying to opt in, the Agency requires that even combustion sources planning to shut down upon entry be operating upon application. The Agency believes a valid distinction exists between replacement arrangements made in response to the Opt-in Program and those that preceded the application to enter the program.

The reason why the combustion source is not operating at the time of application is not relevant to the Agency's determination of whether a retired or non-operating source should be permitted to opt into the Acid Rain Program. Allocating allowances to a retired or non-operating combustion source and allowing the source to trade such allowances would, in effect, allow another source to emit what the retired or non-operating combustion source was emitting before it ceased operations. These allowances would thus result in more pollution being released into the environment. As discussed in the preamble to the proposed rule, Congress expected the SO_2 emissions from non-utility sources to remain at a constant level and to reflect a dynamic balancing of emissions caused by fluctuations in economic activity, shutdowns, facility modernization, fuel switching, and cleanup. By granting sources not operating at the time of application the ability to opt-in and receive allowances, EPA would increase emissions above the presumed constant level of non-utility emissions.

2. Interpretation of Shutdown, Modification and Reconstruction

In the proposed rule, EPA sought to distinguish the modification of an opt-in source from its outright replacement. EPA recognizes that opt-in sources may need to make changes to their facilities in order to reduce emissions. Here, EPA attempts to address the extreme case in which such changes represent the construction of an essentially "new" facility. EPA proposed to consider an opt-in source "shut down" in the circumstance in which the opt-in source had been modified to such a large extent that the opt-in source no longer existed and a new one had been put in its place (in the extreme, the construction of a new facility within the shell of the old one). EPA chose as its test for replacement the reconstruction standard established in 40 CFR 60.15, as discussed in the preamble to the proposed rule.

EPA maintains that a new facility constructed in the shell of an older one should not retain the allowances allocated to the original opt-in source and should be removed from the Opt-in Program. Such restrictions are consistent with section 410(f) of the Act in implementing both the reduced utilization provisions as well as the thermal energy exception. The Agency believes its use of the regulatory term "reconstruction" and its threshold of 50 percent of what would be required to construct a new comparable facility is entirely appropriate in this context, and therefore the Agency applies this standard for reconstruction from 40 CFR 60.15 to opt-in sources. One commenter correctly acknowledged that the 50 percent criterion would apply to improvements to the facility as a whole; however, EPA disputes the notion that the level of investment would prohibit facility improvements to reduce emissions or would restrict alternatives to strictly end-of-pipe options. EPA believes that this level of expenditure is sufficiently high to allow sources great flexibility in their choice of control options.

EPA modifies in the final rule the regulatory language that would exclude reconstructed units from maintaining their status as opt-in sources. Instead of considering such units as "shutdown", the rule explicitly dismisses such units from the program in cases of reconstruction. The effect on sources undergoing modifications qualifying as reconstruction remains the same.

To exclude from consideration the reconstruction of any equipment with equipment that performs the same or similar function would circumvent the need to remove allowances from sources that are no longer in operation. As discussed previously, emissions from these sources are assumed to disappear, consistent with the Congressionally assumed constant level of industrial emissions, and opt-in allowances are assumed to be generated from emission reductions at the opt-in source. The Opt-in Program should not perpetuate emissions from old to new sources, or in this case, from old to reconstructed sources.

The increase in productive capacity at opt-in sources is relevant only to the extent that such investments would trigger a determination of reconstruction. Finally, the use of the definition of major modification to distinguish between reconstructed units and existing opt-in sources is also not appropriate. If a modification is a major modification because a source achieves a significant increase in a regulated pollutant, the source's permitting levels may change, but such changes would not affect its opt-in permit or its allowance levels, provided that such modifications do not also exceed the threshold for reconstruction.

In the context of the Opt-in Program, a reconstructed opt-in source will not be permitted to enter or remain in the Opt-in Program at its pre-reconstruction baseline and allowance allocation. Should the reconstructed and former opt-in source wish to enter the Opt-in Program, after modifications have been completed, it may do so, once it establishes a three-year alternative baseline. Other regulatory programs, including the non-attainment and Prevention of Significant Deterioration (PSD) programs, may or may not consider the reconstructed opt-in source as a "new" source; nevertheless, units undergoing reconstruction will have their allowances deducted and their opt-in permits terminated. Units that do not exceed the level of reconstruction and remain in the Opt-in Program may or may not be subject to New Source Review (NSR) or the New Source Performance Standards (NSPS) but applicability under these programs is independent from participation in the Opt-in Program.

3. Incorporation of Efficiency Measures

Under § 74.44 of the proposed regulation, the only efficiency improvements that would be credited toward utilization were improvements that reduced the demand for electricity or that made electricity generation more efficient. Improvements in the efficiency of steam production, measures to reduce steam load (i.e., steam conservation measures), and sulfur-free generation as defined in § 72.2 were not included.

The final rule allows for efficiency improvements to be incorporated in an opt-in source's annual utilization. Efficiency improvements include any expected reduction in the heat rate at the opt-in source, any expected improvement in the efficiency of steam production at the opt-in source, and any kilowatt hour savings or steam savings from demand side measures.

EPA agrees that improvements in the efficiency of steam generation should be encouraged. EPA believes that some restrictions are necessary, however, because cogeneration facilities could shift their output to steam while decreasing the efficiency of electricity generation. Such shifts from electricity to steam should not result in an adjusted increase in utilization and hence in allowances retained.

In order to prevent such shifts from occurring, today's rule requires that the heat rate at an opt-in source not increase in order to claim an efficiency improvement in steam production. If the heat rate increases, that is, if electricity generation becomes less efficient, no credit for gains in the efficiency of steam production will be given towards utilization. The methodology for quantifying this adjustment to utilization from efficiency increases in steam production will be developed by EPA, working with interested opt-in sources.

EPA also agrees that reductions in steam load created by demand side measures that improve the efficiency of steam consumption should be encouraged. EPA is concerned about the identification of such measures and their verifiable contribution towards using steam more efficiently. The burden for documenting such measures is on the opt-in source, which must be able to demonstrate that the reduction in utilization from a steam conservation measure is different than reductions in utilization not related to conservation improvements.

Finally, EPA also believes that opt-in sources should be encouraged to pursue opportunities to increase their use of sulfur-free technologies at their facilities. However, EPA maintains that such technologies are already included in the provisions providing credit for demand-side measures (see Appendix A, Section 1 of part 73 of this chapter which includes sulfur-free technologies in a list of examples of demand-side measures).

EPA does not include, however, a separate provision for "sulfur-free generation" in the utilization adjustment, because the term, as defined in § 72.2 of this chapter and used in § 72.91, includes all sulfur-free generators in the utility's system. For opt-in sources, EPA restricts adjustments to utilization for improved efficiency to measures performed at the opt-in source itself or by the "customers" of the opt-in source (i.e., electricity or steam users of the opt-in source). The Agency does not include "sulfur-free generation", because of concerns of replacing the opt-in source's utilization without any thermal energy transfer, as required by section 410(f).

4. Expiration of a Non-Effective Opt-in Permit

The proposed rule created an effective date for an opt-in permit to be the later of the issuance of the opt-in permit by the permitting authority or the completion of the certification of the combustion source's monitoring systems. However, no time period was specified regarding the length of time between the issuance of the opt-in permit and these certifications. One commenter requested clarification about this time period and whether or not the opt-in permit would expire before becoming effective.

Response: EPA establishes, in the final rule, an expiration date associated with a non-effective opt-in permit. An opt-in permit will expire 180 days after issuance, if it has not yet become effective. The length of 180 days was selected because the time period incorporates the duration of EPA's review of monitoring certification for the combustion source's CEM systems and two months for the combustion source to arrange testing, should the combustion source wish to wait to certify its monitors until the end of the permitting process.

EPA believes that an expiration date is important to prevent combustion sources from seeking a permit with no immediate intention to opt into the Acid Rain program. A combustion source might apply early to enter the Opt-in Program, but wait to make its permit effective in order to secure an allowance allocation based on its current emissions rate at the time of application. If the combustion source faced the possibility of an impending emission limit that would lower its allowable emissions rate, the combustion source could apply and then wait to install its monitors and undertake its emission reductions. In effect, the combustion source would be seeking to capitalize on emission reductions it would be required to make based on other regulatory requirements.

EPA sees no reason to allow for an extended period of time during which a combustion source can secure its allowance allocation and keep its application pending. EPA wants its applicants to be serious about entering the Opt-in Program and is concerned about behavior that would lead combustion sources to seek an opt-in permit and secure an allowance allocation because of the prospect of future, more stringent emission limitations. In addition, EPA does not want to waste administrative resources in reviewing applications and processing permits for combustion sources that are not ready to participate in the program and may or may not actually opt in. The Agency believes that the time period for the entire permit process plus the 180 days added here, a total of up to 24 months, is sufficiently long for the combustion source to install and certify its monitors considering that the combustion source must submit upon application a monitoring plan, detailing both the monitors' configuration and equipment. EPA may extend this time period of 180 days, if the applying combustion source can show that despite good faith effort towards certifying its monitors, it was unable to complete such certifications within this time frame.

5. Miscellaneous Issues

a. Opt-in Permitting

As discussed in the preamble to the proposed rule (58 FR 50096), the permitting procedures for opt-in sources had been designed to follow the approaches set forth at parts 70 and 72. EPA has found it necessary, however, to modify the permitting procedures in the proposed opt-in regulation to handle inconsistencies between the proposal and parts 70 and 72, some of which were noted by commenters or became evident in permitting Phase I units and establishing part 70 permitting programs. These relatively minor changes in the final rule make the permitting process conform better with the process used to permit utility units affected under the Acid Rain Program.

Of the changes made to improve the regulatory language implementing the opt-in permitting process, a few are worthy of further explanation. First, the roles of the Administrator and the permitting authority have been clarified. Although the Administrator retains an important role in developing an opt-in source's allowance allocation for the combustion source's opt-in permit, the permitting authority has a greater role in the final rule in developing the opt-in permit than was suggested in the proposed regulatory language. Secondly, the time frame under which the State as permitting authority has to process an opt-in permit has been made consistent with part 70. In the final rule, the State has 18 months from the receipt of a complete opt-in permit application or such lesser time as approved under part 70. The proposed regulatory language could have been interpreted to require a permitting decision within 12 months.

There are several other specific changes that relate to opt-in permitting. One concerns the submission of a compliance plan as provided under § 72.40. The opt-in compliance plan must include an explicit commitment on the part of the designated representative to hold allowances in the opt-in source's compliance subaccount equal to or greater than the amount of sulfur dioxide emissions emitted during that year. Another concerns the term of an opt-in permit. Opt-in permits issued prior to January 1, 2000 will expire on December 31, 1999. Opt-in permits issued after January 1, 2000 will have a term of 5 years. Further, a provision has been added to § 74.40 to facilitate the opening of opt-in unit accounts. The designated representative of an opt-in source shall request the opening of such an account in the Allowance Tracking System once its permit is final and effective. In addition, the rule language is clarified concerning the deduction of allowances in the circumstances of withdrawal, shutdown, reconstruction, or change in source's status as unaffected under the mandatory portion of the Acid Rain Program.

EPA neglected to explicitly discuss the permit revision and renewal procedures in the proposed opt-in regulations and includes such language in the final rule. Permit revision procedures follow procedures set forth in subpart H of part 72. The opt-in regulation, part 74, reserves for the permitting authority the preparation of permit revisions and the implementation of such revisions.

Opt-in sources may renew their opt-in permits through the same process in which the opt-in permits were initially issued, except that the permitting authority shall not alter an opt-in source's allowance allocation when issuing a renewal of an opt-in permit. EPA believes that assurance of a consistent stream of opt-in allowances is essential to a viable Opt-in Program. Without a consistent stream of allowances, opt-in sources are unable to plan for future-year compliance, and purchasers of opt-in allowances will be hesitant to enter into forward or futures contracts because of the risk that the allowances may not be available.

EPA also seeks to clarify the relationship of title V and a combustion source's ability to enter the Opt-in Program. Specifically, commenters inquired whether a combustion source must hold a title V permit to be an opt-in source. Another commenter explored the possibility for a mobile source, i.e. a locomotive, to be eligible to opt into the Acid Rain Program.

Consistent with title V of the 1990 Clean Air Act Amendments and regulations promulgated in part 70, all affected sources are considered part 70 sources and therefore are required to meet the permitting requirements under title V. The statute, under section 502(a), makes unlawful "the operation of an affected source (as provided in title IV) * * * except in compliance with a permit issued by a permitting authority under (title V)." Opt-in sources are electing to become affected units and, therefore, are included as affected sources under the Acid Rain Program and in title V (see 42 U.S.C. 7651a(1)). Therefore, all opt-in sources must obtain title V permits.

Particularly in light of the obligation for an affected unit to hold a title V permit, nonstationary sources are excluded from entering the Opt-in Program. Title V expressly applies only to stationary sources (see 42 U.S.C. 7402(a)). Consistent with this statutory provision, the Acid Rain regulations define "source" in a way that refers only to stationary sources: "Source means any * * * structure, installation, plant, building or facility * * *." Consequently, affected units, which must be located at affected sources, also must be stationary. Locomotives, therefore, will not be accepted as potential opt-in sources. EPA has modified the definition of the term "combustion source" to include the explicit requirement that combustion sources be stationary sources.

b. Clarification of Eligible Combustion Sources

The EPA will not require an official applicability determination, as discussed under § 72.6(c), for a combustion source applying to opt into the Acid Rain Program, but the Agency will affirm as part of its review of the opt-in permit application that the combustion source is indeed unaffected and therefore eligible to opt in. Combustion sources should be aware, as detailed in the recently published applicability guidance, "Do the Acid Rain SO_2 Regulations Apply to You?" (EPA 430–R–94–002), that units may be required to provide documentation supporting their unaffected status. Furthermore, that status may, in fact, change over time as certain unaffected units become affected under particular operating or construction conditions. As stated in the final rule under § 74.50(a)(3), should an opt-in source become an affected unit, the Administrator will terminate the opt-in source's opt-in permit and deduct all of the allowances allocated under the Opt-in Program for current and future years.

It is the duty of the combustion source's owner and operator to meet the requirements of the Acid Ra[illegible] [illegible]ogram if the combustion source bec[illegible]s affected. For purposes of kee[illegible]g combustion sources aware of their regulatory status, EPA will add certification statements both to the opt-in permit application and to an opt-in source's annual compliance certification report that will state that the opt-in source is only considered an affected unit under part 74 and not an affected utility unit under § 72.6.

Finally, commenters requested clarification on the eligibility of certain types of sources and sources located outside of the continental U.S. Although the proposed rule was ambiguous regarding the eligibility of unaffected municipal waste combustors, the final rule allows such combustors to be eligible to apply for the Opt-in Program provided that they qualify as a "unit" and burn some amount of fossil fuel. Combustion and process sources that are located outside the continental U.S. (e.g., in Alaska or Hawaii) are not eligible to opt in and the applicability provisions in § 74.2 have been modified to reflect this prohibition.

c. Modification to Utilization Calculation

As discussed in the proposed rule under § 74.44, EPA selected an average utilization to compare against the baseline for making determinations of reduced utilization. This average utilization was calculated as a rolling average of fuel input over three years.

Four commenters agreed with EPA's proposal to use a three-year rolling average for determining reduced utilization because such an approach would smooth out the peaks and valleys that may occur in steam generation from year to year. Two commenters disagreed with EPA's proposal. One suggests that EPA use a five- to eight-year averaging period in order to account for normal economic cycles. The second commenter believed that an average over multiple years would bias the determination of reduced utilization, awarding unnecessary allowances in individual years when emissions could be low or near zero. The commenter suggested that EPA should use annual data because annual SO_2 emissions are proportional to annual fuel use.

Response: EPA will keep its calculation of average utilization overall, but will modify its calculation for the first and second years in which the opt-in source participates in the program and for the first and second years in which the opt-in source is governed by a thermal energy plan. Average utilization for the first year will equal the fuel input of that year. Average utilization for the second year will equal the average of the first two years. Thereafter, average utilization will be as proposed and equal a rolling average of three years.

EPA believes the purpose of using a three-year rolling average to determine whether an opt-in source has reduced its utilization remains the same and remains valid: namely, as the commenters recognize, to smooth out small fluctuations in the operation of opt-in sources. The three-year interval is consistent with the baseline period and provides for a more accurate comparison with the baseline as a measure of utilization than would longer intervals.

EPA modifies its calculation of average utilization for the first two years described above to address possible bias. With regard to the calculation of average utilization outside the context of a thermal energy plan, the Agency notes that in the proposed rule (58 FR 50124), the average for the first two years was based on the baseline level of utilization rather than actual utilization of the opt-in source. With such a methodology, an opt-in source that consistently operates below its baseline level could calculate an artificially high average utilization for its first two years as an opt-in source and thereby avoid allowance surrender. EPA feels that such a windfall would be inappropriate and that the methodology could create the potential for abuse. Therefore, EPA bases average utilization in these first two years on actual utilization for the opt-in source in the first year and then the first two years.

With regard to the calculation of average utilization once an opt-in source becomes governed by a thermal energy plan, EPA believes that the use of a continuing three-year average for the first two years under the plan would distort the number of allowances retained by the opt-in source. The reasoning for modifying the average utilization calculation is similar. Rather than reflecting normal fluctuations in the operation of the opt-in source whose thermal energy has been replaced, the three-year average utilization calculated for the first two years under the plan would award allowances based on the opt-in source's prereplacement levels of utilization and could result in an allowance windfall. Therefore, EPA bases average utilization for the two years immediately after the thermal energy plan takes effect on the actual utilization for the first year and then the average for the first two years.

d. Efficiency Adjustments for an Opt-in Source Governed by a Thermal Energy Plan

EPA clarifies an ambiguity in the proposed rule regarding allowance holdings among an opt-in source and its replacement units if the opt-in source claims efficiency improvements as part of its annual utilization. If the opt-in source has estimated efficiency improvements in its annual utilization and these estimates prove to be incorrect, EPA could be placed in the position of adjusting not only the allowance holdings of the opt-in source, but also the holdings of all replacement units after the reconciliation process has ended (recall that annual compliance reports are submitted in March, while confirmation of energy efficiency estimates are not submitted until July). In order to avoid reassessing the compliance of perhaps multiple replacement units, EPA will consider the number of allowances transferred to replacement units fixed after the reconciliation process has ended and rely on the opt-in source to surrender any additional allowances needed to make the accounting consistent with the confirmed efficiency estimates. EPA maintains that it is reasonable for the opt-in source, which made the initial efficiency estimates, to bear the allowance consequences of correcting those estimates.

e. Definitions

EPA has found it useful to modify certain definitions and to explain certain terms applicable to the Opt-in Program to make its provisions clearer. Consistent with the procedures established in part 72 subpart B and referenced in § 74.4, the owners and operators of a combustion or process source seeking to opt into the Acid Rain Program must select a designated representative. This designated representative is charged with representing the combustion or process source with regards to all matters under the Acid Rain Program. However, during the opt-in permit application process, the combustion or process source is not yet an affected unit nor an affected source, and strictly speaking, may not have a designated representative under the existing definition in § 72.2.

The Agency amends the definition of designated representative in § 72.2 to include a responsible person authorized by the owners and operators of a combustion or process source as a designated representative. This individual has the same role and responsibilities as designated representatives for units affected under the other provisions of title IV and must complete a Certification of Representation as specified in § 72.24. The Certification of Representation should be submitted prior to or concurrent with the opt-in permit application. Further, the definitions of owner and owner or operator have been modified to include the appropriate individuals at combustion and process sources.

In addition, the definition of affected unit has been clarified to include units covered under § 72.6 and part 74 of this chapter to be subject to the Acid Rain emissions reduction requirements or the Acid Rain emissions limitations. EPA also has clarified the usage of the terms "combustion source" and "opt-in source" because of confusion expressed by individual commenters on the proposed rule. Prior to entering the Opt-in Program, the entity wishing to opt-in is referred to, in the final rule, as a combustion source or a process source, as appropriate. Once in the Opt-in Program, the combustion source becomes an opt-in source and is referred to as such throughout the remainder of the rule. An opt-in source is an affected unit under the Acid Rain Program.

Finally, in the preamble to the proposed rule, Table 2 was in error regarding the definition of the opt-in source in various circumstances. The revised Table 2 is as follows:

TABLE 2.—OPT-IN SOURCE DEFINITIONS

Type of configuration at a single site	Single discrete entity?	What is the opt-in source?
Individual boiler emitting to single stack.	Yes	Boiler and stack.
Individual boiler as part of multiple boilers sharing single stack.	Yes, to the extent that monitoring is specific to the opt-in source.	Boiler, duct to the stack.
Multiple boilers sharing single stack.	No	Each boiler and its appropriate duct.*
Individual boiler emitting to multiple stacks.	Yes	Boiler and all stacks.
Multiple boilers sharing multiple stacks.	No	Each boiler and its appropriate ducts.*
Multiple boilers and affected units sharing single/multiple stacks.	No	Each unaffected boiler and its appropriate ducts.*

*—If the combustion sources wish to employ common stack monitoring they may do so according to the provisions of part 75 generally and § 75.16 in particular of the Acid Rain Program.

f. Other Items

Three other miscellaneous changes warrant mention. First, EPA has decided to allow submission of annual data as an alternative to monthly data for baseline calculations. The rule has been altered in several places accordingly. Second, EPA has modified a provision in part 77 to incorporate adjustments to allowance deductions due to differences between estimated and verified reductions in heat input due to conservation, improved electric efficiency, and improved steam production efficiency. Third, Appendix A, containing a draft opt-in permit application form, has been removed from the regulation. Forms will be issued during program implementation and will reflect, where appropriate, comments submitted.

EPA has also made revisions to parts 74 and 75 to better integrate the Opt-in Program with the rest of the Acid Rain Program. The bulk of the regulatory language relating to the monitoring of combustion sources has been moved from Subpart F in part 74 and integrated into part 75 to consolidate all monitoring requirements for all affected units in part 75.

EPA has retained general references to part 76, which is reserved for NO_x regulation, but removed specific references to sections within part 76 in the final rule. This reflects the recent decision of the U.S. Court of Appeals for the District of Columbia Circuit vacating part 76.

Finally, the proposed amendments to part 78 involving the exhaustion of administrative appeals as a necessary prerequisite to judicial review will not be finalized in this rulemaking. Final provisions concerning the exhaustion of administrative remedies will be addressed in a subsequent rulemaking.

g. Display of OMB Control Numbers

EPA is also amending the table of currently approved information collection request (ICR) control numbers issued by OMB for various regulations. This amendment updates the table to accurately display those information requirements contained in this final rule. This display of the OMB control numbers and their subsequent codification in the Code of Federal Regulations satisfies the requirements of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

The ICR was previously subject to public notice and comment prior to OMB approval. As a result, EPA finds that there is "good cause" under section 553(b)(3)(B) of the Administrative Procedure Act (5 U.S.C. 553(b)(3)(B)) to amend this table without prior notice and comment. Due to the technical nature of the table, further notice and comment would be unnecessary. For the same reasons, EPA also finds that there is good cause under 5 U.S.C. 553(d)(3) to make the amendments effective immediately.

D. Impact Analyses

1. Executive Order 12866 (Regulatory Impact Analysis)

Under Executive Order 12866 (58 FR 51735 (October 4, 1993)) the Agency must determine whether a 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.

Pursuant to the terms of Executive Order 12866, OMB has notified EPA that it considers this a "significant regulatory action" within the meaning of the Executive Order. EPA has submitted this action to OMB for review. Any changes made in response to OMB suggestions or recommendations are be documented in the public record.

EPA estimated the total cost savings of the opt-in regulations for the time period from 1994 through 2010. Cost savings are expected to accrue to both affected utilities and opt-in sources. The cost savings depend on the number of allowances sold by opt-in sources and the price of allowances. The estimates assume the use of 1985–87 baseline data, the use of the lesser of 1985 actual or allowable rate, or the current rate at the time the combustion source applies to opt in, reduced allowance allocations for reduced utilization, the transfer of allowances as a result of the replacement of thermal energy at the allowable emission rate at the replacement source, the installation and operation of continuous emissions monitoring systems, and opt-in sources are allowed to withdraw from the program. Given these assumptions, an estimated 408 combustion sources would opt in resulting in annual net cost savings of approximately $10 million. The analysis is contained in the Economic Impact Analysis (EIA) of the Opt-in Regulations, September, 1994, EPA, Office of Atmospheric Programs.

2. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 requires each Federal agency to perform a Regulatory Flexibility Analysis for all rules that are likely to have a "significant impact on a substantial number of small entities." Because the Opt-in Program is a voluntary cost reducing component of the Acid Rain Program, it will not affect small entities adversely. Sources that will not benefit from their participation will choose not to participate. Based on this analysis and pursuant to the provisions of 5 U.S.C. 605(b), EPA hereby certifies that this attached rule, if promulgated, will not have a significant economic impact on a substantial number of small entities.

3. Paperwork Reduction Act

The information collection requirements in this rule have been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq* and have been assigned control number 2060–0258.

This collection of information has an estimated reporting burden averaging 80 hours per response and an estimated annual recordkeeping burden averaging 2 hours per respondent. These estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding the burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to Chief, Information Policy Branch; EPA; 401 M St., SW. (Mail Code 2136); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

List of Subjects

40 CFR Part 9

Reporting and recordkeeping requirements.

40 CFR Part 72

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 73

Environmental protection, Acid rain, Air pollution control, Electric utilities, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 74

Environmental protection, Acid rain, Air pollution control, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 75

Environmental protection, Acid rain, Air pollution control, Carbon dioxide, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 77

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Penalties, Reporting and recordkeeping requirements, Sulfur oxides.

40 CFR Part 78

Environmental protection, Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur oxides.

Dated: March 20, 1995.

Carol M. Browner,

Administrator, U.S. Environmental Protection Agency.

For the reasons set out in the preamble, chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 9—[AMENDED]

1. In part 9:

a. 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, 1321, 1326, 1330, 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.

b. Section 9.1 is amended by adding a new heading and entries in numerical order to the table to read as follows:

§ 9.1 OMB approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * *	* *
Sulfur Dioxide Opt-ins:	
74.12	2060–0258
74.14	2060–0258
74.16	2060–0258
74.18	2060–0258
74.20	2060–0258
74.22	2060–0258
74.24–74.25	2060–0258
74.41	2060–0258
74.43–74.44	2060–0258
74.46–74.47	2060–0258
74.60–74.64	2060–0258
* * *	* *

PART 72—PERMITS REGULATION

2. The authority citation for part 72 is revised to read as follows:

Authority: 42 U.S.C. 7601, 7651, et seq.

3. Section 72.2 is amended as follows:

a. By revising the introductory text;

b. By revising the term for "Acid Rain compliance option";

c. By revising paragraph (1)(i) of the term "Acid Rain emissions limitation";

d. By revising the terms "Acid Rain Program", "Affected unit", "Allowable SO_2 emissions rate", "Allowance deduction", "Compensating unit", "Compliance certification", "Compliance plan; Designated Representative", "Owner", "Owner or Operator", "Phase I unit", "Phase II unit; and Reduced utilization"; and

e. By adding the following terms in alphabetical order, "Combustion source", "Operating", "Opt-in", "Opt-in permit", "Opt-in source", "Replacement unit", and "Thermal energy".

§ 72.2 Definitions.

The terms used in this part, in parts 73, 74, 75, 76, 77 and 78 of this chapter shall have the meanings set forth in the Act, including sections 302 and 402 of the Act, and in this section as follows:

* * * * *

Acid Rain compliance option means one of the methods of compliance used by an affected unit under the Acid Rain Program as described in a compliance plan submitted and approved in accordance with subpart D of this part, part 74 of this chapter or part 76 of this chapter.

Acid Rain emissions limitation means:

(1) For the purposes of sulfur dioxide emissions:

(i) The tonnage equivalent of the allowances authorized to be allocated to an affected unit for use in a calendar year under section 404(a)(1) and (a)(3) of the Act, the basic Phase II allowance allocations authorized to be allocated to an affected unit for use in a calendar year, or the allowances authorized to be allocated to an opt-in source under section 410 of the Act for use in a calendar year;

* * * * *

Acid Rain Program means the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with title IV of the Act, this part, and parts 73, 74, 75, 76, 77, and 78 of this chapter.

* * * * *

Affected unit means a unit that is subject to any Acid Rain emissions reduction requirement or Acid Rain emissions limitation under § 72.6 or part 74 of this chapter.

* * * * *

Allowable SO_2 emissions rate means the most stringent federally enforceable emissions limitation for sulfur dioxide (in lb/mmBtu) applicable to the unit or combustion source for the specified calendar year, or for such subsequent year as determined by the Administrator where such a limitation does not exist for the specified year; provided that, if a Phase I or Phase II unit is listed in the NADB, the "1985 allowable SO_2 emissions rate" for the Phase I or Phase II unit shall be the rate specified by the Administrator in the NADB under the data field "1985 annualized boiler SO_2 emission limit."

* * * * *

Allowance deduction, or deduct when referring to allowances, means the permanent withdrawal of allowances by the Administrator from an Allowance Tracking System compliance subaccount, or future year subaccount, to account for the number of tons of SO_2 emissions from an affected unit for the calendar year, for tonnage emissions estimates calculated for periods of missing data as provided in part 75 of this chapter, or for any other allowance surrender obligations of the Acid Rain Program.

* * * * *

Combustion source means a stationary fossil fuel fired boiler, turbine, or internal combustion engine that has submitted or intends to submit an opt-in permit application under § 74.14 of this chapter to enter the Opt-in Program.

* * * * *

Compensating unit means an affected unit that is not otherwise subject to Acid Rain emissions limitation or Acid Rain emissions reduction requirements during Phase I and that is designated as a Phase I unit in a reduced utilization plan under § 72.43; provided that an opt-in source shall not be a compensating unit.

* * * * *

Compliance certification means a submission to the Administrator or permitting authority, as appropriate, that is required by this part, by part 73, 74, 75, 76, 77, or 78 of this chapter, to report an affected source or an affected unit's compliance or non-compliance with a provision of the Acid Rain Program and that is signed and verified by the designated representative in accordance with subparts B and I of this part and the Acid Rain Program regulations generally.

* * * * *

Compliance plan, for the purposes of the Acid Rain Program, means the document submitted for an affected source in accordance with subpart C of this part or subpart E of part 74 of this chapter, or part 76 of this chapter, specifying the method(s) (including one or more Acid Rain compliance options as provided under subpart D of this part or subpart E of part 74 of this chapter, or part 76 of this chapter by which each affected unit at the source will meet the applicable Acid Rain emissions limitation and Acid Rain emissions reduction requirements.

* * * * *

Designated representative means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source or by the owners and operators of a combustion source or process source, as evidenced by a certificate of representation submitted in accordance with subpart B of this part, to represent and legally bind each owner and operator, as a matter of federal law, in matters pertaining to the Acid Rain Program. Whenever the term "responsible official" is used in part 70 of this chapter, in any other regulations implementing title V of the Act, or in a State operating permit program, it shall be deemed to refer to the "designated representative" with regard to all matters under the Acid Rain Program.

* * * * *

Operating when referring to a combustion or process source seeking entry into the Opt-in Program, means that the source had documented consumption of fuel input for more than 876 hours in the 6 months immediately preceding the submission of a combustion source's opt-in application under § 74.16(a) of this chapter.

* * * * *

Opt in or opt into means to elect to become an affected unit under the Acid Rain Program through the issuance of the final effective opt-in permit under § 74.14 of this chapter.

Opt-in permit means the legally binding written document that is contained within the Acid Rain permit and sets forth the requirements under part 74 of this chapter for a combustion source or a process source that opts into the Acid Rain Program.

Opt-in source means a combustion source or process source that has elected to become an affected unit under the Acid Rain Program and whose opt-in permit has been issued and is in effect

* * * * *

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected unit or in a combustion source or process source; or

(2) Any holder of a leasehold interest in an affected unit or in a combustion source or process source; or

(3) Any purchaser of power from an affected unit or from a combustion source or process source under a life-of-the-unit, firm power contractual arrangement as the term is defined herein and used in section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit; or

(4) With respect to any Allowance Tracking System general account, any

person identified in the submission required by § 73.31(c) of this chapter that is subject to the binding agreement for the authorized account representative to represent that person's ownership interest with respect to allowances.

* * * * *

Owner or operator means any person who is an owner or who operates, controls, or supervises an affected unit, affected source, combustion source, or process source and shall include, but not be limited to, any holding company, utility system, or plant manager of an affected unit, affected source, combustion source, or process source.

* * * * *

Phase I unit means any affected unit, except an affected unit under part 74 of this chapter, that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitations beginning in Phase I.

* * * * *

Phase II unit means any affected unit, except an affected unit under part 74 of this chapter, that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation during Phase II only.

* * * * *

Reduced utilization means a reduction, during any calendar year in Phase I, in the heat input (expressed in mmBtu for the calendar year) at a Phase I unit below the unit's baseline, where such reduction subjects the unit to the requirement to submit a reduced utilization plan under § 72.43; or, in the case of an opt-in source, means a reduction in the average utilization, as specified in § 74.44 of this chapter, of an opt-in source below the opt-in source's baseline.

* * * * *

Replacement unit means an affected unit replacing the thermal energy provided by an opt-in source, where both the affected unit and the opt-in source are governed by a thermal energy plan.

* * * * *

Thermal energy means the thermal output produced by a combustion source used directly as part of a manufacturing process but not used to produce electricity.

* * * * *

4. Section 72.4 is amended by revising paragraphs (a)(1) and (a)(2) to read as follows:

§ 72.4 Federal authority.

(a) * * *

(1) Secure information needed for the purpose of developing, revising, or implementing, or of determining whether any person is in violation of, any standard, method, requirement, or prohibition of the Act, this part, parts 73, 74, 75, 76, 77, and 78 of this chapter;

(2) Make inspections, conduct tests, examine records, and require an owner or operator of an affected unit to submit information reasonably required for the purpose of developing, revising, or implementing, or of determining whether any person is in violation of, any standard, method, requirement, or prohibition of the Act, this part, parts 73, 74, 75, 76, 77, and 78 of this chapter.

* * * * *

5. Section 72.9 is amended by revising paragraphs (g)(6) and (g)(7) to read as follows:

§ 72.9 Standard requirements.

* * * * *

(g) * * *

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under § 72.41 (substitution plans), § 72.42 (Phase I extension plans), § 72.43 (reduced utilization plans), § 72.44 (Phase II repowering extension plans), § 74.47 of this chapter (thermal energy plans), and part 76 of this chapter (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under part 75 of this chapter (including §§ 75.16, 75.17 and 75.18 of this chapter), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of this part, parts 73, 74, 75, 76, 77, and 78 of this chapter, by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

* * * * *

6. Section 72.21 is amended by revising paragraph (e) to read as follows:

§ 72.21 Submissions.

* * * * *

(e) The provisions of this section shall apply to a submission made under parts 73, 74, 75, 76, 77, and 78 of this chapter only if it is made or signed or required to be made or signed, in accordance with parts 73, 74, 75, 76, 77, and 78 of this chapter, by:

(1) The designated representative; or

(2) The authorized account representative or alternate authorized account representative of a unit account.

7. Section 72.30 is amended by revising paragraph (c) to read as follows:

§ 72.30 Requirement to apply.

* * * * *

(c) *Duty to reapply.* The designated representative shall submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or an opt-in permit governing an opt-in source or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted.

8. Section 72.40 is amended by revising paragraph (b)(1) introductory text to read as follows:

§ 72.40 General.

* * * * *

(b) *Multi-unit compliance options.* (1) A plan for a compliance option, under § 72.41, 72.42, 72.43, or 72.44 of this part, under § 74.47 of this chapter, or an NO_X averaging plan contained in part 76 of this chapter, that includes units at more than one affected source shall be complete only if:

* * * * *

9. Section 72.72 is amended by revising paragraph (b)(1) introductory text; and paragraphs (b)(1)(i) (A) and (B), (b)(1)(ii) (A) and (C), (b)(1)(v), (b)(1)(xiv); the first sentence of (b)(5)(i), and paragraph (b)(5)(vi) to read as follows:

§ 72.72 State permit program approval criteria.

* * * * *

(b) * * *

(1) *Acid Rain Permit Issuance.* Issuance or denial of Acid Rain permits shall follow the procedures under this part, part 70 of this chapter, and, for combustion or process sources, part 74, including:

(i) *Permit application*—

(A) *Requirement to comply.*

(1) The owners and operators and the designated representative for each affected source, except for combustion or process sources, under jurisdiction of the State permitting authority shall be required to comply with subparts B, C, and D of this part.

(2) The owners and operators and the designated representative for each combustion or process source under jurisdiction of the State permitting

authority shall be required to comply with subpart B of this part and subparts B, C, D, and E of part 74 of this chapter.

(B) *Effect of an Acid Rain Permit Application.* A complete Acid Rain permit application, except for a permit application for a combustion or process source, shall be binding on the owners and operators and the designated representative of the affected source, all affected units at the source, and any other unit governed by the permit application and shall be enforceable as an Acid Rain permit, from the date of submission of the permit application until the issuance or denial of the Acid Rain permit under paragraph (b)(1)(vii) of this section.

* * * * *

(ii) *Draft permit.*

(A) The State permitting authority shall prepare the draft Acid Rain permit in accordance with subpart E of this part or, for a combustion or process source, subpart B of part 74 of this chapter, or deny a draft Acid Rain permit.

* * * * *

(C) Prior to issuance of a draft permit for a combustion or process source, the State permitting authority shall provide the designated representative of a combustion or process source an opportunity to confirm its intention to opt-in, in accordance with § 74.14 of this chapter.

* * * * *

(v) *Proposed Permit.* Following the public notice and comment period on a draft Acid Rain permit, the permitting authority shall incorporate all changes necessary and issue a proposed Acid Rain permit in accordance with subpart E of this part or, for combustion or process sources, in accordance with subpart B of part 74 of this chapter or deny a proposed Acid Rain permit.

* * * * *

(xiv) Except as provided in § 72.73(b) and, with regard to combustion or process sources, in § 74.14(c)(6) of this chapter, the State permitting authority shall issue or deny an Acid Rain permit within 18 months of receiving a complete Acid Rain permit application submitted in accordance with § 72.21 or such lesser time approved under part 70 of this chapter.

* * * * *

(5) *Acid Rain appeal procedures.*

(i) Appeals of the Acid Rain portion of an operating permit issued by the State permitting authority that do not challenge or involve decisions or actions of the Administrator under this part, parts 73, 74, 75, 76, 77 and 78 of this chapter, shall be conducted according to procedures established by the State under § 70.4(b)(3)(x) of this chapter. * * *

* * * * *

(vi) A failure of the State permitting authority to issue an Acid Rain permit in accordance with § 72.73(b)(1)(i) or, with regard to combustion or process sources, § 74.14(c)(6) of this chapter shall be ground for filing an appeal.

* * * * *

10. Section 72.81 is amended by removing the word "and" from the end of paragraph (b)(3); by replacing the period with "; and" at the end of paragraph (b)(4) and by adding paragraph (b)(5) to read as follows:

§ 72.81 Permit modifications.

* * * * *

(b) * * *

(5) Changes in a thermal energy plan that result in any addition or subtraction of a replacement unit or any change affecting the number of allowances transferred for the replacement of thermal energy.

* * * * *

11. Section 72.83 is amended by revising paragraph (a)(6), (a)(11), and by adding paragraph (a)(12) to read as follows:

§ 72.83 Administrative permit amendment.

(a) * * *

(6)(i) Termination of a compliance option in the permit; provided that all requirements for termination under subpart D of this part are met and this procedure shall not be used to terminate a repowering plan after December 31, 1999 or a Phase I extension plan;

(ii) For opt-in sources, termination of a compliance option in the permit; provided that all requirements for termination under § 74.47 of this chapter are met.

* * * * *

(11) Changes in a thermal energy plan that do not result in the addition or subtraction of a replacement unit or any change affecting the number of allowances transferred for the replacement of thermal energy.

(12) Incorporation of changes that the Administrator has determined to be similar to those in paragraphs (a)(1) through (11) of this section.

* * * * *

PART 73—SULFUR DIOXIDE ALLOWANCE SYSTEM

12. The authority citation for part 73 is revised to read as follows:

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

13. Section 73.34 is amended by revising paragraphs (c)(2) and (c)(6) to read as follows:

§ 73.34 Recordation in accounts.

* * * * *

(c) * * *

(2) All allowances allocated or deducted pursuant to §§ 72.41, 72.42, 72.43, and 72.44 and part 74 of this chapter;

* * * * *

(6) All allowances deducted or returned pursuant to §§ 73.35(d), 72.91 and 72.92, part 74, and part 77 of this chapter.

* * * * *

14. Section 73.35 is amended by revising paragraphs (b)(1) and (b)(2) to read as follows:

§ 73.35 Compliance.

* * * * *

(b) *Deductions for compliance.* (1) Except as provided in paragraph (d) of this section, following the recordation of transfers submitted correctly for recordation in the compliance subaccount pursuant to paragraph (a) of this section and subpart D of this part, the Administrator will deduct allowances from each affected unit's compliance subaccount in accordance with the allowance deduction formula in § 72.95 of this chapter, or, for opt-in sources, the allowance deduction formula in § 74.49 of this chapter, and any correction made under § 72.96 of this chapter. (2) The Administrator will make deductions until either the number of allowances deducted is equal to the amount calculated in accordance with § 72.95 of this chapter, or, for opt-in sources, in accordance with § 74.49 of this chapter, as modified under § 72.96 of this chapter or until no more allowances remain in the compliance subaccount.

* * * * *

15. Section 73.52 is amended by revising paragraphs (a)(3) to read as follows:

§ 73.52 EPA recordation.

* * * * *

(a) * * *

(3) If the allowances identified by serial number specified pursuant to § 73.50(b)(1)(ii) are subject to the limitation on transfer imposed pursuant to § 72.44(h)(1)(i) of this chapter, § 74.42 of this chapter, or § 74.47(c) of this chapter, the transfer is in accordance with such limitation; and

* * * * *

16. Title 40 is amended by adding part 74 to read as follows:

PART 74—SULFUR DIOXIDE OPT-INS

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

Subpart A—Background and Summary

§ 74.1 Purpose and scope.

The purpose of this part is to establish the requirements and procedures for:

(a) The election of a combustion or process source that emits sulfur dioxide to become an affected unit under the Acid Rain Program, pursuant to section 410 of title IV of the Clean Air Act, 42 U.S.C. 7401, *et seq.*, as amended by Public Law 101–549 (November 15, 1990); and

(b) Issuing and modifying operating permits; certifying monitors; and allocating, tracking, transferring, surrendering and deducting allowances for combustion or process sources electing to become affected units.

§ 74.2 Applicability.

Combustion or process sources that are not affected units under § 72.6 of this chapter and that are operating and are located in the 48 contiguous States or the District of Columbia may submit an opt-in permit application to become opt-in sources upon issuance of an opt-in permit. Units for which a written exemption under § 72.7 or § 72.8 of this chapter is in effect and combustion or process sources that are not operating are not eligible to submit an opt-in permit application to become opt-in sources.

§ 74.3 Relationship to the Acid Rain program requirements.

(a) *General.* (1) For purposes of applying parts 72, 73, 75, 77 and 78, each opt-in source shall be treated as an affected unit.

(2) Subpart A, B, G, and H of part 72 of this chapter, including §§ 72.2 (definitions), 72.3 (measurements, abbreviations, and acronyms), 72.4 (federal authority), 72.5 (State authority), 72.6 (applicability), 72.7 (New units exemption), 72.8 (Retired units exemption), 72.9 (Standard Requirements), 72.10 (availability of information), and 72.11 (computation of time), shall apply to this part.

(b) *Permits.* The permitting authority shall act in accordance with this part and parts 70 and 72 of this chapter in issuing or denying an opt-in permit and incorporating it into a combustion or process source's operating permit. To the extent that any requirements of this part, part 72, and part 78 of this chapter are inconsistent with the requirements of part 70 of this chapter, the requirements of this part, part 72, and part 78 of this chapter shall take precedence and shall govern the issuance, denials, revision, reopening, renewal, and appeal of the opt-in permit.

(c) *Appeals.* The procedures for appeals of decisions of the Administrator under this part are contained in part 78 of this chapter.

(d) *Allowances.* A combustion or process source that becomes an affected unit under this part shall be subject to all the requirements of subparts C and D of part 73 of this chapter.

(e) *Excess emissions.* A combustion or process source that becomes an affected unit under this part shall be subject to the requirements of part 77 of this chapter applicable to excess emissions of sulfur dioxide and shall not be subject to the requirements of part 77 of this chapter applicable to excess emissions of nitrogen oxides.

(f) *Monitoring.* A combustion or process source that becomes an affected unit under this part shall be subject to all the requirements of part 75, consistent with subparts F and G of this part.

§ 74.4 Designated representative.

(a) The provisions of subpart B of part 72 of this chapter shall apply to the designated representative of an opt-in source.

(b) If a combustion or process source is located at the same source as one or more affected units, the combustion or process source shall have the same designated representative as the other affected units at the source.

Subpart B—Permitting Procedures

§ 74.10 Roles—EPA and permitting authority.

(a) *Administrator responsibilities.* The Administrator shall be responsible for the following activities under the opt-in provisions of the Acid Rain Program:

(1) *Calculating* the baseline or alternative baseline and allowance allocation, and allocating allowances for combustion or process sources that become affected units under this part;

(2) Certifying or recertifying monitoring systems for combustion or process sources as provided under § 74.62;

(3) Establishing allowance accounts, tracking allowances, assessing end-of-year compliance, determining reduced utilization, approving thermal energy transfer and accounting for the replacement of thermal energy, closing accounts for opt-in sources that shut down, are reconstructed, become affected under § 72.6 of this chapter, or fail to renew their opt-in permit, and deducting allowances as provided under subpart E of this part; and

(4) Ensuring that the opt-in source meets all withdrawal conditions prior to withdrawal from the Acid Rain Program as provided under § 74.18; and

(5) Approving and disapproving the request to withdraw from the Acid Rain Program.

(b) *Permitting authority responsibilities.* The permitting authority shall be responsible for the following activities:

(1) Issuing the draft and final opt-in permit;

(2) Revising and renewing the opt-in permit; and

(3) Terminating the opt-in permit for an opt-in source as provided in § 74.18 (withdrawal), § 74.46 (shutdown, reconstruction or change in affected status) and § 74.50 (deducting allowances).

§ 74.12 Opt-in permit contents.

(a) The opt-in permit shall be included in the Acid Rain permit.

(b) *Scope.* The opt-in permit provisions shall apply only to the opt-in source and not to any other affected units.

(c) *Contents.* Each opt-in permit, including any draft or proposed opt-in permit, shall contain the following elements in a format specified by the Administrator:

(1) All elements required for a complete opt-in permit application as provided under § 74.16 for combustion sources or under § 74.17 for process sources or, if applicable, all elements required for a complete opt-in permit renewal application as provided in § 74.19 for combustion sources or under § 74.17 for process sources;

(2) The allowance allocation for the opt-in source as determined by the Administrator under subpart C of this part for combustion sources or subpart D of this part for process sources;

(3) The standard permit requirements as provided under § 72.9 of this chapter, except that the provisions in § 72.9(d) of this chapter shall not be included in the opt-in permit; and

(4) *Termination.* The provision that participation of a combustion or process source in the Acid Rain Program may be terminated only in accordance with § 74.18 (withdrawal), § 74.46 (shutdown, reconstruction, or change in affected status), and § 74.50 (deducting allowances).

(d) Each opt-in permit is deemed to incorporate the definitions of terms under § 72.2 of this chapter.

(e) *Permit shield.* Each opt-in source operated in accordance with the opt-in permit that governs the opt-in source and that was issued in compliance with title IV of the Act, as provided in this part and parts 72, 73, 75, 77, and 78 of this chapter, shall be deemed to be operating in compliance with the Acid Rain Program, except as provided in § 72.9(g)(6) of this chapter.

(f) *Term of opt-in permit.* An opt-in permit shall be issued for a period of 5 years and may be renewed in accordance with § 74.19; provided

(1) If an opt-in permit is issued prior to January 1, 2000, then the opt-in permit may, at the option of the permitting authority, expire on December 31, 1999; and

(2) If an affected unit with an Acid Rain permit is located at the same source as the combustion source, the combustion source's opt-in permit may, at the option of the permitting authority, expire on the same date as the affected unit's Acid Rain permit expires.

§ 74.14 Opt-in permit process.

(a) *Submission.* The designated representative of a combustion or process source may submit an opt-in permit application and a monitoring plan to the Administrator at any time for any combustion or process source that is operating.

(b) *Issuance or denial of opt-in permits.* The permitting authority shall issue or deny opt-in permits or revisions of opt-in permits in accordance with the procedures in part 70 of this chapter and subparts F and G of part 72 of this chapter, except as provided in this section.

(1) *Supplemental information.* Regardless of whether the opt-in permit application is complete, the Administrator or the permitting authority may request submission of any additional information that the Administrator or the permitting authority determines to be necessary in order to review the opt-in permit application or to issue an opt-in permit.

(2) *Interim review of monitoring plan.* The Administrator will determine, on an interim basis, the sufficiency of the monitoring plan, accompanying the opt-in permit application. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that all SO_2 emissions, NO_x emissions, CO_2 emissions, and opacity of the combustion or process source are monitored and reported in accordance with part 75 of this chapter. This interim review of sufficiency shall not be construed as the approval or disapproval of the combustion or process source's monitoring system.

(3) *Issuance of draft opt-in permit.* After the Administrator determines whether the combustion or process source's monitoring plan is sufficient under paragraph (b)(2) of this section, the permitting authority shall serve the draft opt-in permit or the denial of a draft permit or the draft opt-in permit revisions or the denial of draft opt-in permit revisions on the designated representative of the combustion or process source submitting an opt-in permit application. A draft permit or draft opt-in permit revision shall not be served or issued if the monitoring plan is determined not to be sufficient.

(4) *Confirmation by source of intention to opt-in.* Within 21 calendar days from the date of service of the draft opt-in permit or the denial of the draft opt-in permit, the designated representative of a combustion or process source submitting an opt-in permit application must submit to the Administrator, in writing, a confirmation or recision of the source's intention to become an opt-in source under this part. The Administrator shall treat the failure to make a timely submission as a recision of the source's intention to become an opt-in source and as a withdrawal of the opt-in permit application.

(5) *Issuance of draft opt-in permit.* If the designated representative confirms the combustion or process source's intention to opt in under paragraph (b)(4) of this section, the permitting authority will give notice of the draft opt-in permit or denial of the draft opt-in permit and an opportunity for public comment, as provided under § 72.65 of this chapter with regard to a draft permit or denial of a draft permit if the Administrator is the permitting authority or as provided in accordance with part 70 of this chapter with regard to a draft permit or the denial of a draft permit if the State is the permitting authority.

(6) *Permit decision deadlines.* (i) If the Administrator is the permitting authority, an opt-in permit will be issued or denied within 12 months of receipt of a complete opt-in permit application.

(ii) If the State is the permitting authority, an opt-in permit will be issued or denied within 18 months of receipt of a complete opt-in permit application or such lesser time approved under part 70 of this chapter.

(7) *Withdrawal of opt-in permit application.* A combustion or process source may withdraw its opt-in permit application at any time prior to the issuance of the final opt-in permit. Once a combustion or process source withdraws its application, in order to re-apply, it must submit a new opt-in permit application in accordance with § 74.16 for combustion sources or § 74.17 for process sources.

(d) *Entry into Acid Rain Program.*—(1) *Effective date.* The effective date of the opt-in permit shall be the January 1, April 1, July 1, or October 1 for a combustion or process source providing monthly data under § 74.20, or January 1 for a combustion or process source providing annual data under § 74.20, following the later of the issuance of the opt-in permit by the permitting authority or the completion of monitoring system certification, as provided in subpart F of this part for combustion sources or subpart G of this part for process sources. The combustion or process source shall become an opt-in source and an affected unit as of the effective date of the opt-in permit.

(2) *Allowance allocation.* After the opt-in permit becomes effective, the Administrator will allocate allowances to the opt-in source as provided in § 74.40. If the effective date of the opt-in permit is not January 1, allowances for the first year shall be pro-rated as provided in § 74.28.

(e) *Expiration of opt-in permit.* An opt-in permit that is issued before the completion of monitoring system certification under subpart F of this part for combustion sources or under subpart G of this part for process sources shall expire 180 days after the permitting authority serves the opt-in permit on the designated representative of the combustion or process source governed by the opt-in permit, unless such monitoring system certification is complete. The designated representative may petition the Administrator to extend this time period in which an opt-in permit expires and must explain in the petition why such an extension should be granted. The designated representative of a combustion source governed by an expired opt-in permit and that seeks to become an opt-in source must submit a new opt-in permit application.

§ 74.16 Application requirements for combustion sources.

(a) *Opt-in permit application.* Each complete opt-in permit application for a combustion source shall contain the following elements in a format prescribed by the Administrator:

(1) Identification of the combustion source, including company name, plant name, plant site address, mailing address, description of the combustion source, and information and diagrams on the combustion source's configuration;

(2) Identification of the designated representative, including name, address, telephone number, and facsimile number;

(3) The year and month the combustion source commenced operation;

(4) The number of hours the combustion source operated in the six months preceding the opt-in permit application and supporting documentation;

(5) The baseline or alternative baseline data under § 74.20;

(6) The actual SO_2 emissions rate under § 74.22;

(7) The allowable 1985 SO_2 emissions rate under § 74.23;

(8) The current allowable SO_2 emissions rate under § 74.24;

(9) The current promulgated SO_2 emissions rate under § 74.25;

(10) If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in § 74.47 for combustion sources; and

(11) A statement whether the combustion source was previously an affected unit under this part;

(12) A statement that the combustion source is not an affected unit under § 72.6 of this chapter;

(13) A complete compliance plan for SO_2 under § 72.40 of this chapter; and

(14) The following statement signed by the designated representative of the combustion source: "I certify that the data submitted under subpart C of part 74 reflects actual operations of the combustion source and has not been adjusted in any way."

(b) *Accompanying documents.* The designated representative of the combustion source shall submit a monitoring plan in accordance with § 74.61.

§ 74.17 Application requirements for process sources [Reserved].

§ 74.18 Withdrawal.

(a) *Withdrawal through administrative amendment.* An opt-in source may request to withdraw from the Acid Rain Program by submitting an administrative amendment under § 72.83 of this chapter, provided that the amendment will be treated as received by the permitting authority upon issuance of the notification of the acceptance of the request to withdraw under paragraph (f)(1) of this section.

(b) *Requesting withdrawal.* To withdraw from the Acid Rain Program, the designated representative of an opt-in source shall submit to the Administrator and the permitting authority a request to withdraw effective January 1 of the year after the year in which the submission is made. The submission shall be made no later than December 1 of the calendar year preceding the effective date of withdrawal.

(c) *Conditions for withdrawal.* In order for an opt-in source to withdraw, the following conditions must be met:

(1) By no later than January 30 of the first calendar year in which the withdrawal is to be effective, the designated representative must submit to the Administrator an annual compliance certification report pursuant to § 74.43.

(2) If the opt-in source has excess emissions in the calendar year before the year for which the withdrawal is to be in effect, the designated representative must submit an offset plan for excess emissions, pursuant to part 77 of this chapter, that provides for immediate deduction of allowances.

(d) *Administrator's action on withdrawal.* After the opt-in source meets the requirements for withdrawal under paragraphs (b) and (c) of this section, the Administrator will deduct allowances required to be deducted under § 73.35 of this chapter and part 77 of this chapter and allowances equal in number to and with the same or earlier compliance use date as those allocated under § 74.40 for the first year for which the withdrawal is to be effective and all subsequent years. The Administrator will close the opt-in source's unit account and transfer any remaining allowances to a new general account as specified under § 74.46(c).

(e) *Opt-in source's prior violations.* An opt-in source that withdraws from the Acid Rain Program shall comply with all requirements under the Acid Rain Program concerning all years for which the opt-in source was an affected unit, even if such requirements arise, or must be complied with after the withdrawal takes effect. The withdrawal shall not be a defense against any violation of such requirements of the Acid Rain Program whether the violation occurs before or after the withdrawal takes effect.

(f) *Notification.* (1) After the requirements for withdrawal under paragraphs (b) and (c) of this section are met and after the Administrator's action on withdrawal under paragraph (d) of this section is complete, the Administrator will issue a notification to the permitting authority and the designated representative of the opt-in source of the acceptance of the opt-in source's request to withdraw.

(2) If the requirements for withdrawal under paragraphs (b) and (c) of this section are not met or the Administrator's action under paragraph (d) of this section cannot be completed, the Administrator will issue a notification to the permitting authority and the designated representative of the opt-in source that the opt-in source's request to withdraw is denied. If the opt-in source's request to withdraw is denied, the opt-in source shall remain

in the Opt-in Program and shall remain subject to the requirements for opt-in sources contained in this part.

(g) *Permit amendment.* (1) After the Administrator issues a notification under paragraph (f)(1) of this section that the requirements for withdrawal have been met (including the deduction of the full amount of allowances as required under paragraph (d) of this section), the permitting authority shall amend, in accordance with §§ 72.80 and 72.83 (administrative amendment) of this chapter, the opt-in source's Acid Rain permit to terminate the opt-in permit, not later than 60 days from the issuance of the notification under paragraph (f) of this section.

(2) The termination of the opt-in permit under paragraph (g)(1) of this section will be effective on January 1 of the year for which the withdrawal is requested. An opt-in source shall continue to be an affected unit until the effective date of the termination.

(h) *Reapplication upon failure to meet conditions of withdrawal.* If the Administrator denies the opt-in source's request to withdraw, the designated representative may submit another request to withdraw in accordance with paragraphs (b) and (c) of this section.

(i) *Ability to return to the Acid Rain Program.* Once a combustion or process source withdraws from the Acid Rain Program and its opt-in permit is terminated, a new opt-in permit application for the combustion or process source may not be submitted prior to the date that is four years after the date on which the opt-in permit became effective.

§ 74.19 Revision and renewal of opt-in permit.

(a) The designated representative of an opt-in source may submit revisions to its opt-in permit in accordance with subpart H of part 72 of this chapter.

(b) The designated representative of an opt-in source may renew its opt-in permit by meeting the following requirements:

(1)(i) In order to renew an opt-in permit if the Administrator is the permitting authority for the renewed permit, the designated representative of an opt-in source must submit to the Administrator an opt-in permit application at least 6 months prior to the expiration of an existing opt-in permit.

(ii) In order to renew an opt-in permit if the State is the permitting authority for the renewed permit, the designated representative of an opt-in source must submit to the permitting authority an opt-in permit application at least 18 months prior to the expiration of an existing opt-in permit or such shorter time as may be approved for operating permits under part 70 of this chapter.

(2) Each complete opt-in permit application submitted to renew an opt-in permit shall contain the following elements in a format prescribed by the Administrator:

(i) Elements contained in the opt-in source's initial opt-in permit application as specified under § 74.16(a)(1), (2), (10), (11), (12), and (13).

(ii) An updated monitoring plan, if applicable under § 75.53(b) of this chapter.

(c)(1) Upon receipt of an opt-in permit application submitted to renew an opt-in permit, the permitting authority shall issue or deny an opt-in permit in accordance with the requirements under subpart B of this part, except as provided in paragraph (c)(2) of this section.

(2) When issuing a renewed opt-in permit, the permitting authority shall not alter an opt-in source's allowance allocation as established, under subpart B and subpart C of this part for combustion sources and under subpart B and subpart D of this part for process sources, in the opt-in permit that is being renewed.

Subpart C—Allowance Calculations for Combustion Sources

§ 74.20 Data for baseline and alternative baseline.

(a) *Acceptable data.* (1) The designated representative of a combustion source shall submit either the data specified in this paragraph or alternative data under paragraph (c) of this section. The designated representative shall also submit the calculations under this section based on such data.

(2) The following data shall be submitted for the combustion source for the calendar year(s) under paragraph (a)(3) of this section:

(i) Monthly or annual quantity of each type of fuel consumed, expressed in thousands of tons for coal, thousands of barrels for oil, and million standard cubic feet (scf) for natural gas. If other fuels are used, the combustion source must specify units of measure.

(ii) Monthly or annual heat content of fuel consumed for each type of fuel consumed, expressed in British thermal units (Btu) per pound for coal, Btu per barrel for oil, and Btu per standard cubic foot (scf) for natural gas. If other fuels are used, the combustion source must specify units of measure.

(iii) Monthly or annual sulfur content of fuel consumed for each type of fuel consumed, expressed as a percentage by weight.

(3) *Calendar Years.* (i) For combustion sources that commenced operating prior to January 1, 1985, data under this section shall be submitted for 1985, 1986, and 1987.

(ii) For combustion sources that commenced operation after January 1, 1985, the data under this section shall be submitted for the first three consecutive calendar years during which the combustion source operated after December 31, 1985.

(b) *Calculation of baseline and alternative baseline.*

(1) For combustion sources that commenced operation prior to January 1, 1985, the baseline is the average annual quantity of fuel consumed during 1985, 1986, and 1987, expressed in mmBtu. The baseline shall be calculated as follows:

$$\text{baseline} = \frac{\sum_{\text{Year}=1985}^{1987} \text{annual fuel consumption}}{3}$$

where,

(i) for a combustion source submitting monthly data,

$$\text{annual fuel consumption} = \sum_{\text{months=Jan}}^{\text{Dec}} \sum_{\text{Fuel Types}} \left[\begin{array}{c} \text{quantity of fuel consumed} \\ \times \text{ heat content } \times \text{ unit conversion} \end{array} \right]$$

and unit conversion
= 2 for coal
= 0.001 for oil
= 1 for gas
For other fuels, the combustion source must specify unit conversion; or

(ii) for a combustion source submitting annual data,

$$\text{annual fuel consumption} = \sum_{\text{Fuel Types}} \left[\begin{array}{c} \text{quantity of fuel consumed} \\ \times \text{ heat content } \times \text{ unit conversion} \end{array} \right]$$

and unit conversion
= 2 for coal
= 0.001 for oil
= 1 for gas
For other fuels, the combustion source must specify unit conversion.

(2) For combustion sources that commenced operation after January 1, 1985, the alternative baseline is the average annual quantity of fuel consumed in the first three consecutive calendar years during which the combustion source operated after December 31, 1985, expressed in mmBtu. The alternative baseline shall be calculated as follows:

$$\text{alternative baseline} = \frac{\sum_{\text{First 3 consecutive years}} \text{annual fuel consumption}}{3}$$

where,
"annual fuel consumption" is as defined under paragraph (b)(1)(i) or (ii) of this section.

(c) *Alternative data.*

(1) For combustion sources for which any of the data under paragraph (b) of this section is not available due solely to a natural catastrophe, data as set forth in paragraph (a)(2) of this section for the first three consecutive calendar years for which data is available after December 31, 1985, may be submitted. The alternative baseline for these combustion sources shall be calculated using the equation for alternative baseline in paragraph (b)(2) of this section and the definition of annual fuel consumption in paragraphs (b)(1)(i) or (ii) of this section.

(2) Except as provided in paragraph (c)(1) of this section, no alternative data may be submitted. A combustion source that cannot submit all required data, in accordance with this section, shall not be eligible to submit an opt-in permit application.

(d) *Administrator's action.* The Administrator may accept in whole or in part or with changes as appropriate, request additional information, or reject data or alternative data submitted for a combustion source's baseline or alternative baseline.

§ 74.22 Actual SO_2 emissions rate.

(a) *Data requirements.* The designated representative of a combustion source shall submit the calculations under this section based on data submitted under § 74.20 for the following calendar year:

(1) For combustion sources that commenced operation prior to January 1, 1985, the calendar year for calculating the actual SO_2 emissions rate shall be 1985.

(2) For combustion sources that commenced operation after January 1, 1985, the calendar year for calculating the actual SO_2 emissions rate shall be the first year of the three consecutive calendar years of the alternative baseline under § 74.20(b)(2).

(3) For combustion sources meeting the requirements of § 74.20(c), the calendar year for calculating the actual SO_2 emissions rate shall be the first year of the three consecutive calendar years to be used as alternative data under § 74.20(c).

(b) *SO_2 emissions factor calculation.* The SO_2 emissions factor for each type of fuel consumed during the specified year, expressed in pounds per thousand tons for coal, pounds per thousand barrels for oil and pounds per million cubic feet (scf) for gas, shall be calculated as follows:

SO_2 Emissions Factor
= (average percent of sulfur by weight) x (k),
where,
average percent of sulfur by weight
= annual average, for a combustion source submitting annual data
= monthly average, for a combustion source submitting monthly data
k = 39,000 for bituminous coal or anthracite
= 35,000 for subbituminous coal
= 30,000 for lignite
= 5,964 for distillate (light) oil
= 6,594 for residual (heavy) oil
= 0.6 for natural gas
For other fuels, the combustion source must specify the SO_2 emissions factor.

(c) *Annual SO_2 emissions calculation.* Annual SO_2 Emissions for the specified calendar year, expressed in pounds, shall be calculated as follows:

(1) For a combustion source submitting monthly data,

$$\text{Annual } SO_2 \text{ Emissions} = \sum_{\text{months=Jan}}^{\text{Dec}} \sum_{\text{Fuel Types}} \left[\begin{array}{c} \text{quantity of fuel consumed} \\ \times\ SO_2 \text{ emissions factor} \\ \times\ (1 - \text{control system efficiency}) \\ \times\ (1 - \text{fuel pre-treatment efficiency}) \end{array} \right]$$

(2) For a combustion source submitting annual data:

$$\text{Annual } SO_2 \text{ Emissions} = \sum_{\text{Fuel Types}} \begin{bmatrix} \text{quantity of fuel consumed} \\ \times SO_2 \text{ emissions factor} \\ \times (1 - \text{control system efficiency}) \\ \times (1 - \text{fuel pre-treatment efficiency}) \end{bmatrix}$$

where,

"quantity of fuel consumed" is as defined under § 74.20(a)(2)(A);

"SO_2 emissions factor" is as defined under paragraph (b) of this section;

"control system efficiency" is as defined under § 60.48(a) and part 60, Appendix A, Method 19 of this chapter, if applicable; and

"fuel pre-treatment efficiency" is as defined under § 60.48(a) and part 60, Appendix A, Method 19 of this chapter, if applicable.

(d) *Annual fuel consumption calculation.* Annual fuel consumption for the specified calendar year, expressed in mmBtu, shall be calculated as defined under § 74.20(b)(1) (i) or (ii).

(e) *Actual SO_2 emissions rate calculation.* The actual SO_2 emissions rate for the specified calendar year, expressed in lbs/mmBtu, shall be calculated as follows:

$$\text{Actual } SO_2 \text{ Emissions Rate} = \frac{\text{Annual } SO_2 \text{ Emissions}}{\text{Annual Fuel Consumption}}$$

§ 74.23 1985 Allowable SO_2 emissions rate.

(a) *Data requirements.* (1) The designated representative of the combustion source shall submit the following data and the calculations under paragraph (b) of this section based on the submitted data:

(i) Allowable SO_2 emissions rate of the combustion source expressed in lbs/mmBtu as defined under § 72.2 of this chapter for the calendar year specified in paragraph (a)(2) of this section. If the allowable SO_2 emissions rate is not expressed in lbs/mmBtu, the allowable emissions rate shall be converted to lbs/mmBtu by multiplying the emissions rate by the appropriate factor as specified in Table 1 of this section.

TABLE 1.—FACTORS TO CONVERT EMISSION LIMITS TO POUNDS OF SO_2/mmBtu

Unit measurement	Bituminous coal	Subbituminous coal	Lignite coal	Oil
lbs Sulfur/mmBtu	2.0	2.0	2.0	2.0
% Sulfur in fuel	1.66	2.22	2.86	1.07
ppm SO_2	0.00287	0.00384	....	0.00167
ppm Sulfur in fuel	....	....	....	0.00334
tons SO_2/hour	2×8760/(annual fuel consumption for specified year[1] × 10^3)			
lbs SO_2/hour	8760/(annual fuel consumption for specified year[1] × 10^6)			

[1] Annual fuel consumption as defined under § 74.20(b)(1) (i) or (ii); specified calendar year as defined under § 74.23(a)(2).

(ii) Citation of statute, regulations, and any other authority under which the allowable emissions rate under paragraph (a)(1) of this section is established as applicable to the combustion source;

(iii) Averaging time associated with the allowable emissions rate under paragraph (a)(1) of this section.

(iv) The annualization factor for the combustion source, based on the type of combustion source and the associated averaging time of the allowable emissions rate of the combustion source, as set forth in the Table 2 of this section:

TABLE 2.—ANNUALIZATION FACTORS FOR SO_2 Emission Rates

Type of combustion source	Annualization factor for scrubbed unit	Annualization factor for unscrubbed unit
Unit Combusting Oil, Gas, or some combination	1.00	1.00
Coal Unit with Averaging Time <= 1 day	0.93	0.89
Coal Unit with Averaging Time = 1 week	0.97	0.92
Coal Unit with Averaging Time = 30 days	1.00	0.96
Coal Unit with Averaging Time = 90 days	1.00	1.00
Coal Unit with Averaging Time = 1 year	1.00	1.00
Coal Unit with Federal Limit, but Averaging Time Not Specified	0.93	0.89

(2) *Calendar* Year.

(i) For combustion sources that commenced operation prior to January 1, 1985, the calendar year for the allowable SO_2 emissions rate shall be 1985.

(ii) For combustion sources that commenced operation after January 1, 1985, the calendar year for the allowable SO_2 emissions rate shall be the first year of the three consecutive calendar years of the alternative baseline under § 74.20(b)(2).

(iii) For combustion sources meeting the requirements of § 74.20(c), the calendar year for calculating the allowable SO_2 emissions rate shall be the first year of the three consecutive calendar years to be used as alternative data under § 74.20(c).

(b) *1985 Allowable SO_2 emissions rate calculation.* The allowable SO_2 emissions rate for the specified calendar year shall be calculated as follows:

1985 Allowable SO_2 Emissions Rate = (Allowable SO_2 Emissions Rate) × (Annualization Factor)

§ 74.24 Current allowable SO_2 emissions rate.

The designated representative shall submit the following data:

(a) Current allowable SO_2 emissions rate of the combustion source, expressed in lbs/mmBtu, which shall be the most stringent federally enforceable emissions limit in effect as of the date of submission of the opt-in application. If the allowable SO_2 emissions rate is not expressed in lbs/mmBtu, the allowable emissions rate shall be converted to lbs/mmBtu by multiplying the allowable rate by the appropriate factor as specified in Table 1 in § 74.23(a)(1)(i).

(b) Citations of statute, regulation, and any other authority under which the allowable emissions rate under paragraph (a) of this section is established as applicable to the combustion source;

(c) Averaging time associated with the allowable emissions rate under paragraph (a) of this section.

§ 74.25 Current promulgated SO_2 emissions limit.

The designated representative shall submit the following data:

(a) Current promulgated SO_2 emissions limit of the combustion source, expressed in lbs/mmBtu, which shall be the most stringent federally enforceable emissions limit that has been promulgated as of the date of submission of the opt-in permit application and that either is in effect on that date or will take effect after that date. If the promulgated SO_2 emissions limit is not expressed in lbs/mmBtu, the limit shall be converted to lbs/mmBtu by multiplying the limit by the appropriate factor as specified in Table 1 of § 74.23(a)(1)(i).

(b) Citations of statute, regulation and any other authority under which the emissions limit under paragraph (a) of this section is established as applicable to the combustion source;

(c) Averaging time associated with the emissions limit under paragraph (a) of this section.

(d) Effective date of the emissions limit under paragraph (a) of this section.

§ 74.26 Allocation formula.

(a) The Administrator will calculate the annual allowance allocation for a combustion source based on the data, corrected as necessary, under § 74.20 through § 74.25 as follows:

(1) For combustion sources for which the current promulgated SO_2 emissions limit under § 74.25 is greater than or equal to the current allowable SO_2 emissions rate under § 74.24, the number of allowances allocated for each year equals:

$$\text{Allowances} = \frac{\begin{bmatrix}\text{baseline}\\ \text{or}\\ \text{alternative baseline}\end{bmatrix} \times \text{the lesser of} \begin{bmatrix}\text{the actual } SO_2 \text{ emissions rate}\\ \text{or}\\ \text{the 1985 allowable } SO_2 \text{ emissions rate}\\ \text{or}\\ \text{the current allowable } SO_2 \text{ emissions rate}\end{bmatrix}}{2000}$$

(2) For combustion sources in which the current promulgated SO_2 emissions limit under § 74.25 is less than the current allowable SO_2 emissions rate under § 74.24.

(i) The number of allowances for each year ending prior to the effective date of the promulgated SO_2 emissions limit equals:

$$\text{Allowances} = \frac{\begin{bmatrix}\text{baseline}\\ \text{or}\\ \text{alternative baseline}\end{bmatrix} \times \text{the lesser of} \begin{bmatrix}\text{the actual } SO_2 \text{ emissions rate}\\ \text{or}\\ \text{the 1985 allowable } SO_2 \text{ emissions rate}\\ \text{or}\\ \text{the current allowable } SO_2 \text{ emissions rate}\end{bmatrix}}{2000}$$

(ii) The number of allowances for the year that includes the effective date of the promulgated SO_2 emissions limit and for each year thereafter equals:

$$\text{Allowances} = \frac{\begin{bmatrix}\text{baseline}\\ \text{or}\\ \text{alternative baseline}\end{bmatrix} \times \text{the lesser of} \begin{bmatrix}\text{the actual } SO_2 \text{ emissions rate}\\ \text{or}\\ \text{the 1985 allowable } SO_2 \text{ emissions rate}\\ \text{or}\\ \text{the current promulgated } SO_2 \text{ emissions rate}\end{bmatrix}}{2000}$$

§ 74.28 Allowance allocation for combustion sources becoming opt-in sources on a date other than January 1.

(a) *Dates of entry.* (1) If an opt-in source provided monthly data under § 74.20, the opt-in source's opt-in permit may become effective at the beginning of a calendar quarter as of January 1, April 1, July 1, or October 1.

(2) If an opt-in source provided annual data under § 74.20, the opt-in source's opt-in permit must become effective on January 1.

(b) *Prorating by Calendar Quarter.* Where a combustion source's opt-in permit becomes effective on April 1, July 1, or October 1 of a given year, the Administrator will prorate the allowance allocation for that first year by the calendar quarters remaining in the year as follows:

Allowances for the first year

$$= \left(\frac{\text{first year partial baseline}}{\text{baseline or alternative baseline}}\right) \times \text{annual allocation of allowances for the first year}$$

(1) For combustion sources that commenced operations before January 1, 1985.

$$\text{first year partial baseline} = \frac{\sum_{\text{Year}=1985}^{1987} \text{fuel consumption for remaining calendar quarters}}{3}$$

(2) For combustion sources that commenced operations after January 1, 1985.

$$\text{first year partial baseline} = \sum_{\text{First 3 consecutive years}} \frac{\text{fuel consumption for the remaining calendar quarters}}{3}$$

(3) Under paragraphs (b) (1) and (2) of this section,

(i) "Remaining calendar quarters" shall be the calendar quarters in the first year for which the opt-in permit will be effective.

(ii) Fuel consumption for remaining calendar quarters =

$$\sum_{\text{months}=\text{Apr., Jul., or Oct.}}^{\text{Dec.}} \; \sum_{\text{Fuel Types}} \text{quantity of fuel consumed} \times \text{heat content} \times \text{unit conversion}$$

where unit conversion

= 2 for coal

= 0.001 for oil

= 1 for gas

For other fuels, the combustion source must specify unit conversion;

and where starting month

= April, if effective date is April 1;

= July, if effective date is July 1; and

= October, if effective date is October 1.

Subpart D—Allowance Calculations for Process Sources—[Reserved]

Subpart E—Allowance Tracking and Transfer and End of Year Compliance

§ 74.40 Establishment of opt-in source allowance accounts.

(a) *Establishing accounts.* Not earlier than the date on which a combustion or process source becomes an affected unit under this part and upon receipt of a request for an opt-in account under paragraph (b) of this section, the Administrator will establish an account and allocate allowances in accordance with subpart C of this part for combustion sources or subpart D of this part for process sources. A separate unit account will be established for each opt-in source.

(b) *Request for opt-in account.* The designated representative of the opt-in source shall, on or after the effective date of the opt-in permit as specified in § 74.14(d), submit a letter requesting the opening of an allowance account in the

Allowance Tracking System to the Administrator.

§ 74.41 Identifying allowances.

(a) *Identifying allowances.* Allowances allocated to an opt-in source will be assigned a serial number that identifies them as being allocated under an opt-in permit.

(b) *Submittal of opt-in allowances for auction.* (1) An authorized account representative may offer for sale in the spot auction under § 73.70 of this chapter allowances that are allocated to opt-in sources, if the allowances have a compliance use date earlier than the year in which the spot auction is to be held and if the Administrator has completed the deductions for compliance under § 73.35(b) for the compliance year corresponding to the compliance use date of the offered allowances.

(2) Authorized account representatives may not offer for sale in the advance auctions under § 73.70 of this chapter allowances allocated to opt-in sources.

§ 74.42 Prohibition on future year transfers.

(a) The Administrator will not record a transfer of opt-in allowances allocated to opt-in sources from a future year subaccount into any other future year subaccount in the Allowance Tracking System.

§ 74.43 Annual compliance certification report.

(a) *Applicability and deadline.* For each calendar year in which an opt-in source is subject to the Acid Rain emissions limitations, the designated representative of the opt-in source shall submit to the Administrator, no later than 60 days after the end of the calendar year, an annual compliance certification report for the opt-in source in lieu of any annual compliance certification report required under subpart I of part 72 of this chapter.

(b) *Contents of report.* The designated representative shall include in the annual compliance certification report the following elements, in a format prescribed by the Administrator, concerning the opt-in source and the calendar year covered by the report:

(1) Identification of the opt-in source;

(2) An opt-in utilization report in accordance with § 74.44 for combustion sources and § 74.45 for process sources;

(3) A thermal energy compliance report in accordance with § 74.47 for combustion sources and § 74.48 for process sources, if applicable;

(4) Shutdown or reconstruction information in accordance with § 74.46, if applicable;

(5) A statement that the opt-in source has not become an affected unit under § 72.6 of this chapter;

(6) At the designated representative's option, the total number of allowances to be deducted for the year, using the formula in § 74.49, and the serial numbers of the allowances that are to be deducted; and

(7) At the designated representative's option, for opt-in sources that share a common stack and whose emissions of sulfur dioxide are not monitored separately or apportioned in accordance with part 75 of this chapter, the percentage of the total number of allowances under paragraph (b)(6) of this section for all such affected units that is to be deducted from each affected unit's compliance subaccount; and

(8) The compliance certification under paragraph (c) of this section.

(c) *Annual compliance certification.* In the annual compliance certification report under paragraph (a) of this section, the designated representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the opt-in source in compliance with the Acid Rain Program, whether the opt-in source was operated during the calendar year covered by the report in compliance with the requirements of the Acid Rain Program applicable to the opt-in source, including:

(1) Whether the opt-in source was operated in compliance with applicable Acid Rain emissions limitations, including whether the opt-in source held allowances, as of the allowance transfer deadline, in its compliance subaccount (after accounting for any allowance deductions or other adjustments under § 73.34(c) of this chapter) not less than the opt-in source's total sulfur dioxide emissions during the calendar year covered by the annual report;

(2) Whether the monitoring plan that governs the opt-in source has been maintained to reflect the actual operation and monitoring of the opt-in source and contains all information necessary to attribute monitored emissions to the opt-in source;

(3) Whether all the emissions from the opt-in source or group of affected units (including the opt-in source) using a common stack were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports in accordance with part 75 of this chapter;

(4) Whether the facts that form the basis for certification of each monitor at the opt-in source or group of affected units (including the opt-in source) using a common stack or of an opt-in source's qualifications for using an Acid Rain Program excepted monitoring method or approved alternative monitoring method, if any, have changed;

(5) If a change is required to be reported under paragraph (c)(4) of this section, specify the nature of the change, the reason for the change, when the change occurred, and how the unit's compliance status was determined subsequent to the change, including what method was used to determine emissions when a change mandated the need for monitoring recertification; and

(6) When applicable, whether the opt-in source was operating in compliance with its thermal energy plan as provided in § 74.47 for combustion sources and § 74.48 for process sources.

§ 74.44 Reduced utilization for combustion sources.

(a) *Calculation of Utilization.*

(1) *Annual utilization.* (i) Except as provided in paragraph (a)(1)(ii) of this section, annual utilization for the calendar year shall be calculated as follows:

Annual Utilization = Actual heat input + Reduction from improved efficiency

where,

(A) "Actual heat input" shall be the actual annual heat input (in mmBtu) of the opt-in source for the calendar year determined in accordance with Appendix F of part 75 of this chapter.

(B) "Reduction from improved efficiency" shall be the sum of the following four elements: Reduction from demand side measures that improve the efficiency of electricity consumption; reduction from demand side measures that improve the efficiency of steam consumption; reduction from improvements in the heat rate at the opt-in source; and reduction from improvement in the efficiency of steam production at the opt-in source. Qualified demand side measures applicable to the calculation of utilization for opt-in sources are listed in Appendix A, Section 1 of part 73 of this chapter.

(C) "Reduction from demand side measures that improve the efficiency of electricity consumption" shall be a good faith estimate of the expected kilowatt hour savings during the calendar year for such measures and the corresponding reduction in heat input (in mmBtu) resulting from those measures. The demand side measures shall be implemented at the opt-in source, in the residence or facility to which the opt-in source delivers electricity for consumption or in the residence or facility of a customer to whom the opt-in source's utility system sells electricity. The verified amount of such reduction shall be submitted in accordance with paragraph (c)(2) of this section.

(D) "Reduction from demand side measures that improve the efficiency of steam consumption" shall be a good faith estimate of the expected steam savings (in mmBtu) from such measures during the calendar year and the corresponding reduction in heat input (in mmBtu) at the opt-in source as a result of those measures. The demand side measures shall be implemented at the opt-in source or in the facility to which the opt-in source delivers steam for consumption. The verified amount of such reduction shall be submitted in accordance with paragraph (c)(2) of this section.

(E) "Reduction from improvements in heat rate" shall be a good faith estimate of the expected reduction in heat rate during the calendar year and the corresponding reduction in heat input (in mmBtu) at the opt-in source as a result of all improved unit efficiency measures at the opt-in source and may include supply-side measures listed in Appendix A, section 2.[illegible] of part 73 of this chapter. The verified amount of such reduction shall be submitted in accordance with paragraph (c)(2) of this section.

(F) "Reduction from improvement in the efficiency of steam production at the opt-in source" shall be a good faith estimate of the expected improvement in the efficiency of steam production at the opt-in source during the calendar year and the corresponding reduction in heat input (in mmBtu) at the opt-in source as a result of all improved steam production efficiency measures. In order to claim improvements in the efficiency of steam production, the designated representative of the opt-in source must demonstrate to the satisfaction of the Administrator that the heat rate of the opt-in source has not increased. The verified amount of such reduction shall be submitted in accordance with paragraph (c)(2) of this section.

(G) Notwithstanding paragraph (a)(1)(i)(B) of this section, where two or more opt-in sources, or two or more opt-in sources and Phase I units, include in their annual compliance certification reports their good faith estimate of kilowatt hour savings or steam savings from the same demand side measures that improve the efficiency of electricity or steam consumption:

(*1*) The designated representatives of all such opt-in sources and Phase I units shall submit with their annual compliance certification reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings or steam savings among such opt-in sources and Phase I units.

(*2*) Each designated representative shall include in its annual compliance certification report only its share of kilowatt hour savings or steam savings.

(ii) For an opt-in source whose opt-in permit becomes effective on a date other than January 1, annual utilization for the first year shall be calculated as follows:

$$\text{Annual Utilization} = \frac{\text{Actual heat input}}{\text{for the remaining calendar quarters}} + \frac{\text{Reduction from improved efficiency}}{\text{for the remaining calendar quarters}}$$

where "actual heat input" and "reduction from improved efficiency" are defined as set forth in paragraph (a)(1)(i) of this section but are restricted to data or estimates for the "remaining calendar quarters", which are the calendar quarters that begin on or after the date the opt-in permit becomes effective.

(2) *Average utilization.* Average utilization for the calendar year shall be defined as the average of the annual utilization calculated as follows:

(i) For the first two calendar years after the effective date of an opt-in permit taking effect on January 1 or for the first two calendar years after the effective date of a thermal energy plan governing an opt-in source in accordance with § 74.47 of this chapter, average utilization will be calculated as follows:

(A) Average utilization for the first year = annual $\text{utilization}_{\text{year 1}}$

where "annual $\text{utilization}_{\text{year 1}}$" is as calculated under paragraph (a)(1)(i) of this section.

(B) Average utilization for the second year

$$= \left(\frac{\text{revised annual utilization}_{\text{year 1}} + \text{annual utilization}_{\text{year 2}}}{2} \right)$$

where,

"revised annual $\text{utilization}_{\text{year 1}}$" is as submitted for the year under paragraph (c)(2)(i)(B) of this section and adjusted under paragraph (c)(2)(iii) of this section;

"annual $\text{utilization}_{\text{year 2}}$" is as calculated under paragraph (a)(1)(i) of this section.

(ii) For the first three calendar years after the effective date of the opt-in permit taking effect on a date other than January 1, average utilization will be calculated as follows:

(A) Average utilization for the first year after opt-in = annual $\text{utilization}_{\text{year 1}}$

where "annual $\text{utilization}_{\text{year 1}}$" is as calculated under paragraph (a)(1)(ii) of this section.

(B) Average utilization for the second year after opt-in

where.

$$= \left(\frac{\text{revised annual utilization}_{\text{year 1}} + \text{annual utilization}_{\text{year 2}}}{\left(\begin{array}{c}\text{Number of months}\\ \text{in year 1 and year 2 for which}\\ \text{the opt-in permit is effective}\end{array} \right)} \right) \times 12$$

"revised annual utilization$_{\text{year 1}}$" is as submitted for the year under paragraph (c)(2)(i)(B) of this section and adjusted under paragraph (c)(2)(iii) of this section; and

"annual utilization$_{\text{year 2}}$" is as calculated under paragraph (a)(1)(ii) of this section.

(C) Average utilization for the third year after opt-in

$$= \left(\frac{\text{revised annual utilization}_{\text{year 1}} + \text{revised annual utilization}_{\text{year 2}} + \text{annual utilization}_{\text{year 3}}}{\left(\begin{array}{c}\text{Number of months}\\ \text{in year 1, year 2, and year 3}\\ \text{for which the opt-in permit is effective}\end{array} \right)} \right) \times 12$$

where,

"revised annual utilization$_{\text{year 1}}$" is as submitted for the year under paragraph (c)(2)(i)(B) of this section and adjusted under paragraph (c)(2)(iii) of this section; and

"revised annual utilization$_{\text{year 2}}$" is as submitted for the year under paragraph (c)(2)(i)(B) of this section and adjusted under paragraph (c)(2)(iii) of this section; and

"annual utilization$_{\text{year 3}}$" is as calculated under paragraph (a)(1)(ii) of this section.

(iii) Except as provided in paragraphs (a)(2)(i) and (a)(2)(ii), average utilization shall be the sum of annual utilization for the calendar year and the revised annual utilization, submitted under paragraph (c)(2)(i)(B) of this section and adjusted by the Administrator under paragraph (c)(2)(iii) of this section, for the two immediately preceding calendar years divided by 3.

(b) *Determination of reduced utilization and calculation of allowances.*—

(1) *Determination of reduced utilization.* For a year during which its opt-in permit is effective, an opt-in source has reduced utilization if the opt-in source's average utilization for the calendar year, as calculated under paragraph (a) of this section, is less than its baseline.

(2) *Calculation of allowances deducted for reduced utilization.* If the Administrator determines that an opt-in source has reduced utilization for a calendar year during which the opt-in source's opt-in permit is in effect, the Administrator will deduct allowances, as calculated under paragraph (b)(2)(i) of this section, from the compliance subaccount of the opt-in source's Allowance Tracking System account.

(i) Allowances deducted for reduced utilization =

$$\text{Number of allowances allocated for the calendar year} \times \left(1 - \left(\frac{\text{average utilization}_{\text{calendar year}}}{\text{baseline}} \right) \right)$$

(ii) The allowances deducted shall have the same or an earlier compliance use date as those allocated under subpart C of this part for the calendar year for which the opt-in source has reduced utilization.

(c) *Compliance.*—(1) *Opt-in Utilization Report.* The designated representative for each opt-in source shall submit an opt-in utilization report for the calendar year, as part of its annual compliance certification report under § 74.43, that shall include the following elements in a format prescribed by the Administrator:

(i) The name, authorized account representative identification number, and telephone number of the designated representative of the opt-in source;

(ii) The opt-in source's account identification number in the Allowance Tracking System;

(iii) The opt-in source's annual utilization for the calendar year, as defined under paragraph (a)(1) of this section, and the revised annual utilization, submitted under paragraph (c)(2)(i)(B) of this section and adjusted under paragraph (c)(2)(iii) of this section, for the two immediately preceding calendar years;

(iv) The opt-in source's average utilization for the calendar year, as defined under paragraph (a)(2) of this section;

(v) The difference between the opt-in source's average utilization and its baseline;

(vi) The number of allowances that shall be deducted, if any, using the formula in paragraph (b)(2)(i) of this section and the supporting calculations;

(2) *Confirmation report.* (i) If the annual compliance certification report for an opt-in source includes estimates of any reduction in heat input resulting from improved efficiency as defined under paragraph (a)(1)(i) of this section, the designated representative shall submit, by July 1 of the year in which the annual compliance certification report was submitted, a confirmation report, concerning the calendar year covered by the annual compliance certification report. The Administrator may grant, for good cause shown, an extension of the time to file the confirmation report. The confirmation

report shall include the following elements in a format prescribed by the Administrator:

(A) *Verified reduction in heat input.* Any verified kwh savings or any verified steam savings from demand side measures that improve the efficiency of electricity or steam consumption, any verified reduction in the heat rate at the opt-in source, or any verified improvement in the efficiency of steam production at the opt-in source achieved and the verified corresponding reduction in heat input for the calendar year that resulted.

(B) *Revised annual utilization.* The opt-in source's annual utilization for the calendar year as provided under paragraph (c)(1)(iii) of this section, recalculated using the verified reduction in heat input for the calendar year under paragraph (c)(2)(i)(A) of this section.

(C) *Revised average utilization.* The opt-in source's average utilization as provided under paragraph (c)(1)(iv) of this section, recalculated using the verified reduction in heat input for the calendar year under paragraph (c)(2)(i)(A) of this section.

(D) *Recalculation of reduced utilization.* The difference between the opt-in source's recalculated average utilization and its baseline.

(E) *Allowance adjustment.* The number of allowances that should be credited or deducted using the formulas in paragraphs (c)(2)(iii)(C) and (D) of this section and the supporting calculations; and the number of adjusted allowances remaining using the formula in paragraph (c)(2)(iii)(E) of this section and the supporting calculations.

(ii) *Documentation.* (A) For all figures under paragraphs (c)(2)(i)(A) of this section, the opt-in source must provide as part of the confirmation report, documentation (which may follow the EPA Conservation Verification Protocol) verifying the figures to the satisfaction of the Administrator.

(B) Notwithstanding paragraph (c)(2)(i)(A) of this section, where two or more opt-in sources, or two or more opt-in sources and Phase I units include in the confirmation report under paragraph (c)(2) of this section or § 72.91(b) of this chapter the verified kilowatt hour savings or steam savings defined under paragraph (c)(2)(i)(A) of this section, for the calendar year, from the same specific measures:

(1) The designated representatives of all such opt-in sources and Phase I units shall submit with their confirmation reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings or steam savings as defined under paragraph (c)(2)(i)(A) of this section for the calendar year among such opt-in sources.

(2) Each designated representative shall include in the opt-in source's confirmation report only its share of the verified reduction in heat input as defined under paragraph (c)(2)(i)(A) of this section for the calendar year under the certification under paragraph (c)(2)(ii)(B)(1) of this section.

(iii) *Determination of reduced utilization based on confirmation report.* (A) If an opt-in source must submit a confirmation report as specified under paragraph (c)(2) of this section, the Administrator, upon such submittal, will adjust his or her determination of reduced utilization for the calendar year for the opt-in source. Such adjustment will include the recalculation of both annual utilization and average utilization, using verified reduction in heat input as defined under paragraph (c)(2)(i)(A) of this section for the calendar year instead of the previously estimated values.

(B) *Estimates confirmed.* If the total, included in the confirmation report, of the amounts of verified reduction in the opt-in source's heat input equals the total estimated in the opt-in source's annual compliance certification report for the calendar year, then the designated representative shall include in the confirmation report a statement indicating that is true.

(C) *Underestimate.* If the total, included in the confirmation report, of the amounts of verified reduction in the opt-in source's heat input is greater than the total estimated in the opt-in source's annual compliance certification report for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be credited to the opt-in source's compliance subaccount calculated using the following formula:

Allowances credited for the calendar year in which the reduced utilization occurred=

$$\text{Number of allowances allocated for the calendar year} \times \left[\frac{\text{Average utilization}_{\text{Verified}} - \text{Average utilization}_{\text{Estimate}}}{\text{baseline}}\right]$$

where,

Average Utilization$_{\text{estimate}}$=
the average utilization of the opt-in source as defined under paragraph (a)(2) of this section, calculated using the estimated reduction in the opt-in source's heat input under (a)(1) of this section, and submitted in the annual compliance certification report for the calendar year.

Average Utilization$_{\text{verified}}$=
the average utilization of the opt-in source as defined under paragraph (a)(2) of this section, calculated using the verified reduction in the opt-in source's heat input as submitted under paragraph (c)(2)(i)(A) of this section by the designated representative in the confirmation report.

(D) *Overestimate.* If the total of the amounts of verified reduction in the opt-in source's heat input included in the confirmation report is less than the total estimated in the opt-in source's annual compliance certification report for the calendar year, then the designated representative shall include in the confirmation report the number of allowances to be deducted from the opt-in source's compliance subaccount, which equals the absolute value of the result of the formula for allowances credited under paragraph (c)(2)(iii)(C) of this section.

(E) *Adjusted allowances remaining.* Unless paragraph (c)(2)(iii)(B) of this section applies, the designated representative shall include in the confirmation report the adjusted amount of allowances that would have been held in the opt-in source's compliance subaccount if the deductions made under § 73.35(b) of this chapter had been based on the verified, rather than the estimated, reduction in the opt-in source's heat input, calculated as follows:

$$\text{Adjusted amount of allowances} = \begin{array}{l}\text{Allowances held after deduction} - \text{Excess emissions} \\ + \text{Allowances credited} - \text{Allowances deducted}\end{array}$$

where:

"Allowances held after deduction" shall be the amount of allowances held in the opt-in source's compliance subaccount after deduction of allowances was made under § 73.35(b) of this chapter based on the annual compliance certification report.

"Excess emissions" shall be the amount (if any) of excess emissions determined under § 73.35(d) for the calendar year based on the annual compliance certification report.

"Allowances credited" shall be the amount of allowances calculated under paragraph (c)(2)(iii)(C) of this section.

"Allowances deducted" shall be the amount of allowances calculated under paragraph (c)(2)(iii)(D) of this section.

(1) If the result of the formula for "adjusted amount of allowances" is negative, the absolute value of the result constitutes excess emissions of sulfur dioxide. If the result is positive, there are no excess emissions of sulfur dioxide.

(2) If the amount of excess emissions of sulfur dioxide calculated under "adjusted amount of allowances" differs from the amount of excess emissions of sulfur dioxide determined under § 73.35 of this chapter based on the annual compliance certification report, then the designated representative shall include in the confirmation report a demonstration of:

(i) The number of allowances that should be deducted to offset any increase in excess emissions or returned to the account for any decrease in excess emissions; and

(ii) The amount of the excess emissions penalty (excluding interest) that should be paid or returned to the account for the change in excess emissions.

(3) The Administrator will deduct immediately from the opt-in source's compliance subaccount the amount of allowances necessary to offset any increase in excess emissions or will return immediately to the opt-in source's compliance subaccount the amount of allowances that he or she determines is necessary to account for any decrease in excess emissions.

(4) The designated representative may identify the serial numbers of the allowances to be deducted or returned. In the absence of such identification, the deduction will be on a first-in, first-out basis under § 73.35(c)(2) of this chapter and the identification of allowances returned will be at the Administrator's discretion.

(5) If the designated representative of an opt-in source fails to submit on a timely basis a confirmation report, in accordance with paragraph (c)(2) of this section, with regard to the estimate of reductions in heat input as defined under paragraph (c)(2)(i)(A) of this section, then the Administrator will reject such estimate and correct it to equal zero in the opt-in source's annual compliance certification report that includes that estimate. The Administrator will deduct immediately, on a first-in, first-out basis under § 73.35(c)(2) of this chapter, the amount of allowances that he or she determines is necessary to offset any increase in excess emissions of sulfur dioxide that results from the correction and will require the owners and operators of the opt-in source to pay an excess emission penalty in accordance with part 77 of this chapter.

(F) If the opt-in source is governed by an approved thermal energy plan under § 74.47 and if the opt-in source must submit a confirmation report as specified under paragraph (c)(2) of this section, the adjusted amount of allowances that should remain in the opt-in source's compliance subaccount shall be calculated as follows:

Adjusted amount of allowances =

$$= \text{allowances allocated} - \text{tons emitted} - \text{the larger of} \left(\begin{array}{c} \text{allowances transferred} \\ \text{to all replacement units} \\ \text{or} \\ \text{allowances deducted} \\ \text{for reduced utilization} \end{array} \right)$$

where,

"Allowances allocated" shall be the original number of allowances allocated under section § 74.40 for the calendar year.

"Tons emitted" shall be the total tons of sulfur dioxide emitted by the opt-in source during the calendar year, as reported in accordance with subpart F of this part for combustion sources.

"Allowances transferred to all replacement units" shall be the sum of allowances transferred to all replacement units under an approved thermal energy plan in accordance with § 74.47 and adjusted by the Administrator in accordance with § 74.47(d)(2).

"Allowances deducted for reduced utilization" shall be the total number of allowances deducted for reduced utilization as calculated in accordance with this section including any adjustments required under paragraph (c)(iii)(E) of this section.

§ 74.45 Reduced utilization for process sources. [Reserved]

§ 74.46 Opt-in source permanent shutdown, reconstruction, or change in affected status.

(a) *Notification.* (1) When an opt-in source has permanently shutdown during the calendar year, the designated representative shall notify the Administrator of the date of shutdown, within 30 days of such shutdown.

(2) When an opt-in source has undergone a modification that qualifies as a reconstruction as defined in § 60.15 of this chapter, the designated representative shall notify the Administrator of the date of completion of the reconstruction, within 30 days of such completion.

(3) When an opt-in source becomes an affected unit under § 72.6 of this chapter, the designated representative shall notify the Administrator of such change in the opt-in source's affected status within 30 days of such change.

(b) *Administrator's action.* (1) The Administrator will terminate the opt-in source's opt-in permit and deduct allowances as provided below in the following circumstances:

(i) When an opt-in source has permanently shutdown. The Administrator shall deduct allowances equal in number to and with the same or earlier compliance use date as those allocated to the opt-in source under § 74.40 for the calendar year in which the shut down occurs and for all future years following the year in which the shut down occurs; or

(ii) When an opt-in source has undergone a modification that qualifies as a reconstruction as defined in § 60.15 of this chapter. The Administrator shall deduct allowances equal in number to and with the same or earlier compliance use date as those allocated to the opt-in source under § 74.40 for the calendar year in which the reconstruction is completed and all future years following the year in which the reconstruction is completed; or

(iii) When an opt-in source becomes an affected unit under § 72.6 of this chapter. The Administrator shall deduct allowances equal in number to and with the same or earlier compliance use date as those allocated to the opt-in source under § 74.40 for the calendar year in which the opt-in source becomes affected under § 72.6 of this chapter and all future years following the calendar year in which the opt-in source becomes affected under § 72.6; or

(iv) When an opt-in source does not renew its opt-in permit. The Administrator shall deduct allowances equal in number to and with the same or earlier compliance use date as those allocated to the opt-in source under § 74.40 for the calendar year in which the opt-in source's opt-in permit expires and all future years following the year in which the opt-in source's opt-in permit expires.

(2) After the allowance deductions under paragraph (b)(1) of this section are made, the Administrator will close the opt-in source's unit account in the Allowance Tracking System. If any allowances remain in the opt-in source's unit account after allowance deductions are made under paragraph (b)(1) of this section, and any deductions made under part 77 of this chapter, the Administrator will establish a general account for the opt-in source, and transfer any remaining allowances into this general account. The designated representative for the opt-in source shall become the authorized account representative for the general account.

§ 74.47 Transfer of allowances from the replacement of thermal energy—combustion sources.

(a) *Thermal energy plan.—(1) General provisions.* The designated representative of an opt-in source that seeks to qualify for the transfer of allowances based on the replacement of thermal energy by a replacement unit shall submit a thermal energy plan subject to the requirements of § 72.40(b) of this chapter for multi-unit compliance options and this section. The effective period of the thermal energy plan shall begin from January 1 of the first full calendar year for which the plan is approved and end December 31 of the last full calendar year for which the opt-in permit containing the plan is in effect.

(2) *Applicability.* This section shall apply to any designated representative of an opt-in source and any designated representative of each replacement unit seeking to transfer allowances based on the replacement of thermal energy.

(3) *Contents.* Each thermal energy plan shall contain the following elements in a format prescribed by the Administrator:

(i) The calendar year that the thermal energy plan takes effect, which shall be the first year the replacement unit(s) will replace thermal energy of the opt-in source;

(ii) The name, authorized account representative identification number, and telephone number of the designated representative of the opt-in source;

(iii) The name, authorized account representative identification number, and telephone number of the designated representative of each replacement unit;

(iv) The opt-in source's account identification number in the Allowance Tracking System;

(v) Each replacement unit's account identification number in the Allowance Tracking System (ATS);

(vi) The type of fuel used by each replacement unit;

(vii) The allowable SO_2 emissions rate, expressed in lbs/mmBtu, of each replacement unit for the calendar year for which the plan will take effect. When a thermal energy plan is renewed in accordance with paragraph (a)(9) of this section, the allowable SO_2 emission rate at each replacement unit will be the most stringent federally enforceable allowable SO_2 emissions rate applicable at the time of renewal for the calendar year for which the renewal will take effect. This rate will not be annualized;

(viii) The estimated amount of total thermal energy to be reduced at the opt-in source, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application;

(ix) The estimated total thermal energy at each replacement unit for the year prior to the year for which the plan is to take effect, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application;

(x) The estimated amount of total thermal energy at each replacement unit after replacing thermal energy at the opt-in source, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application;

(xi) The estimated amount of thermal energy at each replacement unit, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application, replacing the thermal energy at the opt-in source;

(xii) Estimated total annual fuel input at each replacement unit after replacing thermal energy at the opt-in source;

(xiii) The number of allowances calculated under paragraph (b) of this section that the opt-in source will transfer to each replacement unit represented in the thermal energy plan.

(xiv) The estimated number of allowances to be deducted for reduced utilization under § 74.44;

(xv) Certification that each replacement unit has entered into a legally binding steam sales agreement to provide the thermal energy, as calculated under paragraph (a)(3)(xi) of this section, that it is replacing for the opt-in source. The designated representative of each replacement unit shall maintain and make available to the Administrator, at the Administrator's request, copies of documents demonstrating that the replacement unit is replacing the thermal energy at the opt-in source.

(4) *Submission.* The designated representative of the opt-in source seeking to qualify for the transfer of allowances based on the replacement of thermal energy shall submit a thermal energy plan to the permitting authority by no later than July 1 of the calendar year prior to the first calendar year for which the plan is to be in effect. The thermal energy plan shall be signed and certified by the designated representative of the opt-in source and each replacement unit covered by the plan.

(5) *Retirement of opt-in source upon enactment of plan.* (i) If the opt-in source will be permanently retired as of the effective date of the thermal energy plan, the opt-in source shall not be required to monitor its emissions upon retirement, consistent with § 75.67 of this chapter, provided that the following requirements are met:

(A) The designated representative of the opt-in source shall include in the plan a request for an exemption from the requirements of part 75 in accordance with § 75.67 of this chapter and shall submit the following statement: "I certify that the opt-in source ("is" or "will be", as applicable) permanently retired on the date specified in this plan and will not emit any sulfur dioxide or nitrogen oxides after such date."

(B) The opt-in source shall not emit any sulfur dioxide or nitrogen oxides after the date specified in the plan.

(ii) Notwithstanding the monitoring exemption discussed in paragraph (a)(5)(i) of this section, the designated representative for the opt-in source shall submit the annual compliance certification report provided under paragraph (d) of this section.

(6) *Administrator's action.* If the permitting authority approves a thermal

energy plan, the Administrator will annually transfer allowances to the Allowance Tracking System account of each replacement unit, as provided in the approved plan.

(7) *Incorporation, modification and renewal of a thermal energy plan.* (i) An approved thermal energy plan, including any revised or renewed plan that is approved, shall be incorporated into both the opt-in permit for the opt-in source and the Acid Rain permit for each replacement unit governed by the plan. Upon approval, the thermal energy plan shall be incorporated into the Acid Rain permit for each replacement unit pursuant to the requirements for administrative permit amendments under § 72.83 of this chapter.

(ii) In order to revise an opt-in permit to add an approved thermal energy plan or to change an approved thermal energy plan, the designated representative of the opt-in source shall submit a plan or a revised plan under paragraph (a)(4) of this section and meet the requirements for permit revisions under § 72.80 and either § 72.81 or § 72.82 of this chapter.

(8) *Termination of plan.* (i) A thermal energy plan shall be in effect until the earlier of the expiration of the opt-in permit for the opt-in source or the year for which a termination of the plan takes effect under paragraph (a)(8)(ii) of this section.

(ii) *Termination of plan by opt-in source and replacement units.* A notification to terminate a thermal energy plan in accordance with § 72.40(d) of this chapter shall be submitted no later than December 1 of the calendar year for which the termination is to take effect.

(iii) If the requirements of paragraph (a)(8)(ii) of this section are met and upon revision of the opt-in permit of the opt-in source and the Acid Rain permit of each replacement unit governed by the thermal energy plan to terminate the plan pursuant to § 72.83 of this chapter, the Administrator will adjust the allowances for the opt-in source and the replacement units to reflect the transfer back to the opt-in source of the allowances transferred from the opt-in source under the plan for the year for which the termination of the plan takes effect.

(9) *Renewal of thermal energy plan.* The designated representative of an opt-in source may renew the thermal energy plan as part of its opt-in permit renewal in accordance with § 74.19.

(b) *Calculation of transferable allowances*—(1) *Qualifying thermal energy.* The amount of thermal energy credited towards the transfer of allowances based on the replacement of thermal energy shall equal the qualifying thermal energy and shall be calculated for each replacement unit as follows:

$$\text{Qualifying thermal energy} = \begin{array}{c}\text{the estimated thermal energy}\\ \text{at the replacement unit}\\ \text{under paragraph (a)(3)(xi) of this section}\end{array}$$

(2) *Fuel associated with qualifying thermal energy.* The fuel associated with the qualifying thermal energy at each replacement unit shall be calculated as follows:

$$\begin{array}{c}\text{Fuel associated with}\\ \text{Qualifying thermal energy}\end{array} = \frac{\text{Qualifying thermal energy}}{\text{Efficiency constant}}$$

where,

"Qualifying thermal energy" for the replacement unit is as defined in paragraph (b)(1) of this section;

"Efficiency constant" for the replacement unit

= 0.85, where the replacement unit is a boiler

= 0.80, where the replacement unit is a cogenerator

(3) *Allowances transferable from the opt-in source to each replacement unit.* The number of allowances transferable from the opt-in source to each replacement unit for the replacement of thermal energy is calculated as follows:

$$\begin{array}{c}\text{transferable allowances}\\ \text{for the replacement unit}\end{array} = \frac{\begin{array}{c}\text{Fuel Associated with}\\ \text{Qualifying thermal energy}\end{array} \times \begin{array}{c}\text{allowable } SO_2 \text{ emission rate}_{\text{replacement unit}}\\ \text{(in lb/mmBtu)}\end{array}}{2000}$$

where,

"Allowable SO_2 emission rate" for the replacement unit is as defined in paragraph (a)(3)(vii) of this section;

"Fuel associated with qualifying thermal energy" is as defined in paragraph (b)(2) of this section;

(c) *Transfer prohibition.* The allowances transferred from the opt-in source to each replacement unit shall not be transferred from the unit account of the replacement unit to any other account in the Allowance Tracking System.

(d) *Compliance*—(1) *Annual compliance certification report.* (i) As required for all opt-in sources, the designated representative of the opt-in source covered by a thermal energy plan must submit an opt-in utilization report for the calendar year as part of its annual compliance certification report under § 74.44(c)(1).

(ii) The designated representative of an opt-in source must submit a thermal energy compliance report for the calendar year as part of the annual compliance certification report, which must include the following elements in a format prescribed by the Administrator:

(A) The name, authorized account representative identification number, and telephone number of the designated representative of the opt-in source;

(B) The name, authorized account representative identification number, and telephone number of the designated representative of each replacement unit;

(C) The opt-in source's account identification number in the Allowance Tracking System (ATS);

(D) The account identification number in the Allowance Tracking System (ATS) for each replacement unit;

(E) The actual amount of total thermal energy reduced at the opt-in source during the calendar year, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application;

(F) The actual amount of thermal energy at each replacement unit, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application, replacing the thermal energy at the opt-in source;

(G) The actual amount of total thermal energy at each replacement unit after replacing thermal energy at the opt-in source, including all energy flows (steam, gas, or hot water) used for any process or in any heating or cooling application;

(H) Actual total fuel input at each replacement unit as determined in accordance with part 75 of this chapter;

(I) Calculations of allowance adjustments to be performed by the Administrator in accordance with paragraph (d)(2) of this section.

(2) *Allowance adjustments by Administrator.* (i) The Administrator will adjust the number of allowances in the Allowance Tracking System accounts for the opt-in source and for each replacement unit to reflect any changes between the estimated values submitted in the thermal energy plan pursuant to paragraph (a) of this section and the actual values submitted in the thermal energy compliance report pursuant to paragraph (d) of this section. The values to be considered for this adjustment include:

(A) The number of allowances transferable by the opt-in source to each replacement unit, calculated in paragraph (b) of this section using the actual, rather than estimated, thermal energy at the replacement unit replacing thermal energy at the opt-in source.

(B) The number of allowances deducted from the Allowance Tracking System account of the opt-in source, calculated under § 74.44(b)(2).

(ii) If the opt-in source includes in the opt-in utilization report under § 74.44 estimates for reductions in heat input, then the Administrator will adjust the number of allowances in the Allowance Tracking System accounts for the opt-in source and for each replacement unit to reflect any differences between the estimated values submitted in the opt-in utilization report and the actual values submitted in the confirmation report pursuant to § 74.44(c)(2).

(3) *Liability.* The owners and operators of an opt-in source or a replacement unit governed by an approved thermal energy plan shall be liable for any violation of the plan or this section at that opt-in source or replacement unit that is governed by the thermal energy plan, including liability for fulfilling the obligations specified in part 77 of this chapter and section 411 of the Act.

§ 74.48 Transfer of allowances from the replacement of thermal energy—process sources [Reserved]

§ 74.49 Calculation for deducting allowances.

(a) *Allowance deduction formula.* The following formula shall be used to determine the total number of allowances to be deducted for the calendar year from the allowances held in an opt-in source's compliance subaccount as of the allowance transfer deadline applicable to that year:

Total allowances deducted = Tons emitted + Allowances deducted for reduced utilization where:

(1)(i) Except as provided in paragraph (a)(1)(ii) of this section, "Tons emitted" shall be the total tons of sulfur dioxide emitted by the opt-in source during the calendar year, as reported in accordance with subpart F of this part for combustion sources or subpart G of this part for process sources.

(ii) If the effective date of the opt-in source's permit took effect on a date other than January 1, "Tons emitted" for the first calendar year shall be the total tons of sulfur dioxide emitted by the opt-in source during the calendar quarters for which the opt-in source's opt-in permit is effective, as reported in accordance with subpart F of this part for combustion sources or subpart G of this part for process sources.

(2) "Allowances deducted for reduced utilization" shall be the total number of allowances deducted for reduced utilization as calculated in accordance with § 74.44 for combustion sources or § 74.45 for process sources.

§ 74.50 Deducting opt-in source allowances from ATS accounts.

(a) *Deduction of allowances.* The Administrator may deduct any allowances that were allocated to an opt-in source under § 74.40 by removing, from any Allowance Tracking System accounts in which they are held, the allowances in an amount specified in paragraph (d) of this section, under the following circumstances:

(1) When the opt-in source has permanently shut down; or

(2) When the opt-in source has been reconstructed; or

(3) When the opt-in source becomes an affected unit under § 72.6 of this chapter; or

(4) When the opt-in source fails to renew its opt-in permit.

(b) *Method of deduction.* The Administrator will deduct allowances beginning with those allowances with the latest recorded date of transfer out of the opt-in source's unit account.

(c) *Notification of deduction.* When allowances are deducted, the Administrator will send a written notification to the authorized account representative of each Allowance Tracking System account from which allowances were deducted. The notification will state:

(1) The serial numbers of all allowances deducted from the account,

(2) The reason for deducting the allowances, and

(3) The date of deduction of the allowances.

(d) *Amount of deduction.* The Administrator may deduct allowances in accordance with paragraph (a) of this section in an amount required to offset any excess emissions in accordance with part 77 of this chapter and when an opt-in source does not hold allowances equal in number to and with the same or earlier compliance use date for the calendar years specified under § 74.46(b)(1) (i) through (iv) in an amount required to be deducted under § 74.46(b)(1) (i) through (iv).

Subpart F—Monitoring Emissions: Combustion Sources

§ 74.60 Monitoring requirements.

(a) *Monitoring requirements for combustion sources.* The owner or operator of each combustion source shall meet all of the requirements specified in part 75 of this chapter for the owners and operators of an affected unit to install, certify, operate, and maintain a continuous emission monitoring system, an excepted monitoring system, or an approved alternative monitoring system in accordance with part 75 of this chapter.

(b) *Monitoring requirements for opt-in sources.* The owner or operator of each opt-in source shall install, certify, operate, and maintain a continuous emission monitoring system, an excepted monitoring system, an approved alternative monitoring system in accordance with part 75 of this chapter.

§ 74.61 Monitoring plan.

(a) *Monitoring plan.* The designated representative of a combustion source shall meet all of the requirements specified under part 75 of this chapter for a designated representative of an affected unit to submit to the Administrator a monitoring plan that includes the information required in a monitoring plan under § 75.53 of this chapter. This monitoring plan shall be submitted as part of the combustion source's opt-in permit application under § 74.14 of this part.

(b) [Reserved].

Subpart G—Monitoring Emissions: Process Sources—[Reserved]

PART 75—CONTINUOUS EMISSION MONITORING

17. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7651, *et seq.*

18. Section 75.4 is amended by revising paragraph (a) introductory text, and by adding paragraph (a)(5) to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the acid rain permit which governs the unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the acid rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an opt-in permit application in accordance with § 74.14 of this chapter. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all certification tests for the required continuous emission monitoring systems and continuous opacity monitoring systems are completed not later than the following dates (except as provided in paragraphs (d) and (e) of this section):

* * * * *

(5) For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the expiration date of a combustion source's opt-in permit under § 74.14(e) of this chapter.

* * * * *

19. Section 75.16 is amended by revising paragraph (a)(2)(ii)(A) and (b)(2)(ii)(A) to read as follows:

§ 75.16 Special provisions for monitoring emissions from common by-pass, and multiple stacks for SO_2 emissions and heat input determinations.

(a) * * *

(2) * * *

(ii) * * *

(A) Designate the Phase II units as substitution units according to the procedure in part 72 of this chapter and the non-affected units as opt-in sources in accordance with part 74 of this chapter and combine emissions for compliance purposes; or

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(A) Designate the non-affected units as opt-in sources in accordance with part 74 of this chapter and combine emissions for compliance purposes; or

* * * * *

20. Section 75.20 is amended by revising the first sentence after the heading in paragraph (a)(3) to read as follows:

§ 75.20 Certification and recertification procedures.

(a) * * *

(3) *Provisional approval of certification applications.* Upon the successful completion of the required certification procedures for each continuous emission or opacity monitoring system or component thereof and subsequent submittal of a complete certification application in accordance with § 75.63, each continuous emission or opacity monitoring system or component thereof shall be deemed provisionally certified for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification application; provided that no continuous emission or opacity monitoring systems for a combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter shall be deemed provisionally certified for use under the Acid Rain Program. * * *

* * * * *

21. Section 75.63 is amended by revising paragraph (a) and (b)(1) to read as follows:

§ 75.63 Certification or recertification application.

(a) *Submission.* The designated representative for an affected unit or a combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter shall submit the request to the Administrator within 30 days after completing the certification test.

(b) * * *

(1) A copy of the monitoring plan (or any modifications to the monitoring plan) for the unit, or units, or combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter, if not previously submitted.

* * * * *

22. Section 75.67 is revised to read as follows:

§ 75.67 Retired units petitions.

(a) For units that will be permanently retired prior to January 1, 1995, an exemption from the requirements of this part, including the requirement to install and certify a continuous emissions monitoring system, may be obtained from the Administrator if the designated representative submits a complete petition, as required in § 72.8 of this chapter, to the Administrator prior to the deadline in § 75.4 by which the continuous emission or opacity monitoring systems must complete the required certification tests.

(b) For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter that will be permanently retired and governed upon entry into the Opt-in Program by a thermal energy plan in accordance with § 74.47 of this chapter, an exemption from the requirements of this part, including the requirement to install and certify a continuous emissions monitoring system, may be obtained from the Administrator if the designated representative submits to the Administrator a petition for such an exemption prior to the deadline in § 75.4 by which the continuous emission or opacity monitoring systems must complete the required certification tests.

PART 77—EXCESS EMISSIONS

23. The authority citation for part 77 revised to read as follows:

Authority: 42 U.S.C. 7601 and 7651, et seq.

24. Section 77.6 is amended by revising paragraph (a) to read as follows:

§ 77.6 Penalties for excess emissions of sulfur dioxide and nitrogen oxides.

(a) If excess emissions of sulfur dioxide or nitrogen oxides occur at an affected unit during any year, the owners and operators of the affected unit shall pay, without demand, an excess emissions penalty, as calculated under paragraph (b) of this section.

Such payment shall be submitted to the Administrator no later than 60 days after the end of any year during which excess emissions occurred at an affected unit or, for any increase in excess emissions of sulfur dioxide determined after adjustments made under § 72.91(b) of this chapter, or § 74.44(c)(2) of this chapter, by July 31 of the year in which the adjustments are made.

* * * * *

PART 78—APPEALS PROCEDURES FOR ACID RAIN PROGRAM

25. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

26. Section 78.1 is amended by revising paragraphs (b)(3) and (b)(4) and by adding paragraph (b)(5) to read as follows:

§ 78.1 Purpose and scope.

(b) * * *

(3) Under part 74 of this chapter,

(i) The determination of incompleteness of an opt-in permit application;

(ii) The issuance or denial of an opt-in permit and approval or disapproval of the transfer of allowances for the replacement of thermal energy;

(iii) The approval or disapproval of a permit revision to an opt-in permit;

(iv) The decision on the deduction or return of allowances under subpart E of part 74 of this chapter;

(4) Under part 75 of this chapter,

(i) The decision on a petition for approval of an alternative monitoring system;

(ii) The approval or disapproval of a monitoring system certification or recertification;

(iii) The finalization of annual emissions data, including retroactive adjustment based on audit;

(iv) The determination of the percentage of emissions reduction achieved by qualifying Phase I technology; and

(v) The determination on the acceptability of parametric missing data procedures for a unit equipped with add-on controls for sulfur dioxide and nitrogen oxides in accordance with part 75 of this chapter.

(5) Under part 77 of this chapter, the determination of incompleteness of an offset plan and the approval or disapproval of an offset plan under § 77.4 of this chapter and the deduction of allowances under § 77.5(c) of this chapter.

* * * * *

27. Section 78.3 is amended by revising paragraph (a)(1) introductory text, and paragraph (d)(2) to read as follows:

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a) * * *

(1) The following persons may petition for administrative review of a decision of the Administrator that is made under parts 72, 74, 75, 76, and 77 of this chapter and that is appealable under § 78.1(a) of this part:

* * * * *

(d) * * *

(2) Any provision or requirement of parts 72, 73, 74, 75, 76, or 77 of this chapter, including any standard requirement under § 72.9 of this chapter and any emissions monitoring or reporting requirements under part 75 of this chapter;

* * * * *

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November 22, 1994

Part IV

Environmental Protection Agency

40 CFR Part 72
Acid Rain Program: Permits; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 72

[FRL–5109–8]

RIN 2060—AF59

Acid Rain Program: Permits

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act, as amended by Public Law 101-549, the Clean Air Act Amendments of 1990 (the Act), authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. On January 11, 1993, the Agency promulgated final rules under title IV. Several parties filed petitions for review of the rules. On November 18, 1993, the Agency published a notice of proposed revisions of those rules implementing sections 404(b) and (c) (substitution plans) and 408(c)(1)(B) (reduced utilization plans) of the Act. On May 4, 1994, EPA and other parties signed a settlement agreement addressing substitution and reduced utilization issues.

After reviewing the record, EPA concludes that the January 11, 1993 rules can be read to give utilities an ability to use substitution and reduced utilization plans to create excess, new allowances. These allowances will authorize sulfur dioxide emissions in excess of total emissions without the plans and will result from emission reductions made, or required by federal or State law adopted, before enactment of title IV. This creation of allowances is contrary to the purposes of sections 404(b) and (c) and 408(c)(1)(B) and can compromise achievement of the emissions reductions intended under title IV. Consequently, EPA is modifying sections of part 72 of the January 11, 1993 regulations. The rule revisions will prevent the use of substitution and reduced utilization plans to create excess, new allowances and are consistent with the May 4, 1994 settlement.

EFFECTIVE DATE: December 22, 1994.

ADDRESSES: Docket No. A–93–40, containing supporting information used to develop the proposal, copies of all comments received, and responses to comments, is available for public inspection and copying from 8:30 a.m. to 12:00 p.m. and 1:00 p.m. to 3:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section (LE-131), Waterside Mall, room 1500, 1st floor, 401 M Street, SW., Washington DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Dwight C. Alpern, Attorney-advisor, at (202) 233-9151, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St., SW., Washington, DC 20460, or the Acid Rain Hotline at (202) 233–9620.

SUPPLEMENTARY INFORMATION: The contents of the preamble to the final rule are as follows:

I. Statutory Purposes of the Substitution and Reduced Utilization Provisions

The provisions in sections 404(b) and (c) and 408(c)(1)(B) of the Act concerning substitution and reduced utilization plans have specific statutory purposes related to the achievement of the sulfur dioxide emissions reduction goals of title IV. The Agency maintains that Congress did not intend that these provisions provide utilities an ability to create excess, new allowances by bringing Phase II units into Phase I. Because the January 11, 1993 regulations implementing these provisions can be read to allow the creation of excess, new allowances in Phase I, the Agency is revising today the regulations to ensure that this does not occur. *See* 58 FR 60951 (defining "excess, new allowances").

As discussed in the preamble of the November 18, 1993 proposal (58 FR 60950–60951), Congress established substitution plans as a compliance option to increase units' compliance flexibility and reduce their overall costs of compliance in Phase I while still achieving the emissions reductions intended by Congress under title IV. A substitution plan allows the owner or operator of a unit listed in Table A of section 404 to reassign the unit's emissions reduction obligations to a designated non-Table A unit under the owner's or operator's control. Upon approval of the reassignment, the non-Table A unit becomes subject to all requirements for Phase I units with regard to sulfur dioxide and is allocated allowances. Emissions reductions by the non-Table A unit may therefore free up allowances, which may be used by the Table A unit (or any other unit) in lieu of making emissions reductions.

Section 404(b)(5) of the Act expressly states that, with a substitution plan, the intended emissions reductions must still be achieved. That section requires that, in approving a substitution plan, the Administrator ensure that the substitution results in total emissions reductions at least equal to the total reductions that otherwise "would have been achieved" by these Table A and non-Table A units "without such substitution." 42 U.S.C. 7651c(b)(5). EPA concludes that the substitution provision is intended to provide an alternative means of achieving Phase I reductions, not a mechanism for avoiding such emission reductions.

The provision for reduced utilization plans has a statutory purpose that is also aimed at ensuring realization of emission reductions. As explained in the November 18, 1993 preamble (58 FR 60951), Congress recognized that the potential for circumvention of emission limitation requirements exists because in Phase I only a minority of all utility units are subject to such requirements. A Phase I unit could simply reduce its utilization by shifting its generation, and the emissions that would otherwise result, to a unit that was not required to use allowances to cover its emissions. Allowances allocated to the Phase I unit would be freed up for use without achievement, at either unit, of the intended emissions reductions.

In section 408(c)(1)(B), Congress adopted a solution to this problem. Owners and operators of any Phase I unit that, for compliance purposes, propose reducing utilization of the unit below 1985-87 utilization (i.e., its baseline) in order to comply with title

IV are required to submit a reduced utilization plan. In such a plan, the owners and operators must designate the units that will provide generation to compensate for the reduced utilization of the Phase I unit or must account for the reduced utilization through energy conservation or improved unit efficiency. 42 U.S.C. 7651(c)(1)(B). Each compensating unit in an approved plan becomes subject to Phase I sulfur dioxide emissions limitations and is allocated allowances equal to that unit's baseline times the lesser of the 1985 actual or allowable emissions rate for the unit. The compensating unit will therefore have to use allowances to account for its emissions, including any increased emissions resulting from compensating generation that it provides for the Phase I unit.

The Administrator approves or disapproves each plan (and compensating units proposed therein) after determining whether the plan meets the requirements of title IV, including achievement of the intended emissions reductions under the Acid Rain Program. 42 U.S.C. 7651g(c)(2); *see also* 58 FR 60951. Thus, like the provisions for substitution plans, the provisions for designating compensating units in reduced utilization plans are intended to allow compliance flexibility but also to protect the emission reduction goals of title IV by requiring that plans not result in more emissions than would occur without the plans. In fact, if the reduced utilization plan provisions were interpreted to allow the creation of excess, new allowances, utilities could simply use such plans to circumvent the limitation on the creation of allowances under substitution plans by bringing the same Phase II units into Phase I as compensating units rather than substitution units.[1]

[1] This conclusion is not contradicted by the legislative history, cited by some commenters, discussing the compliance flexibility and potential cost savings resulting from use of the allowance market. *See, e.g.*, Senate Rep. No. 101–228 at 316. Such generic discussion of the ability of units to over- or under- control emissions and to trade allowances does not address the specific issue of the entry of Phase II units into Phase I. Although, under the Partial Settlement in *Environmental Defense Fund* v. *Carol M. Browner*, No. 93–1203 and *Alabama Power Co.* v. *U.S. EPA*, No. 93–1611 (D.C. Cir. 1993) (signed May 4 and 20, 1993), many comments on the November 18, 1993 proposal were withdrawn, the Agency is responding—here or in a response-to-comment document—to the substance of all comments that were originally submitted. (This settlement is hereafter referred to as "the May 4, 1994 settlement".)

II. Need to Modify the January 11, 1993 Regulations

A. The January 11, 1993 Regulations can be Read to Give Utilities the Ability to Bring Phase II Units Into Phase I and Create Excess, New Allowances

On January 11, 1993, EPA promulgated regulations that implemented the major provisions of title IV, including the substitution and reduced utilization provisions. As discussed in the November 18, 1993 preamble (58 FR 60951–60953), these provisions can be read to provide utilities two alternative methods of bringing into Phase I, with few limitations, selected Phase II units and creating excess, new allowances. The Agency concludes that both provisions must be revised in order to eliminate this problem.

Under § 72.41 of the January 11, 1993 regulations, the designated representative for a unit on Table A may include in the Phase I permit application a substitution plan designating, as substitution units, one or more existing units that are Phase II units and so not on Table A. 40 CFR 72.41(b) (1993). There is no express requirement that the substitution unit make reductions beyond those that it would have made without the plan or actually provide allowances for the Table A unit and no express limit on the number of substitution units that a Table A unit may designate. Further, for the most part, the decision whether to designate a particular Phase II unit as a substitution unit is at the discretion of the utility. *See* 58 FR 60952.

Section 72.43 of the January 11, 1993 regulations requires, under certain circumstances, that the designated representative for a Phase I unit submit a reduced utilization plan designating a compensating unit. Such a plan must be submitted if the owners and operators of the unit plan to reduce utilization of the unit below its baseline for purposes of complying with Phase I emissions limitations and to accomplish this by shifting generation to a non-Phase I unit. 40 CFR 72.43(b) (1993). Because of concern that utilities would be unable to designate compensating units and therefore might engage in uneconomic dispatching to avoid reduced utilization requiring such designations, the regulation establishes broad exceptions to the requirement to submit a plan. 40 CFR 72.43(e) (1993); *see also* 58 FR 60958–60959. There is no express requirement that the Phase I unit actually have any reduced utilization or the compensating unit actually provide any compensating generation to the Phase I unit. There is also no express limit on the number of compensating units that a Phase I unit may designate and no express bar on a compensating unit itself designating a compensating unit. Further, as with substitution units, a utility's decision to designate a compensating unit is largely discretionary. *See* 58 FR 60952.

Because utilities generally have broad discretion and flexibility in designating substitution and compensating units, such units will likely be designated only if early entry into Phase I is beneficial, e.g., where early entry creates new allowances because the units have lower actual emissions in Phase I than the allowances they will receive as substitution or compensating units. *See* 58 FR 60953 and n. 2. Before the enactment of title IV, some Phase II units had reduced emissions rates for economic or other reasons and some States had already adopted laws requiring their utilities to reduce emissions rates prior to Phase II. Such reductions occurred, or will occur, for reasons independent of the substitution and reduced utilization provisions. Under the January 11, 1993 regulations, for each Phase I year that a substitution or reduced utilization plan is in effect, each substitution or compensating unit under the plan is allocated a number of allowances equal to the unit's baseline times the lesser of the 1985 actual or allowable emissions rate for the unit. 40 CFR 72.41(c)(3) and (d) and 72.43(c)(4)(ii) and (d) (1993). Consequently, some Phase II units may enter Phase I as substitution or compensating units and convert emission rate reductions into excess, new allowances: i.e., allowances that would not otherwise be available and that reflect emission rate reductions that would occur even without plans allowing early entry into Phase I.

The excess, new allowances may become available to affected units in Phase I and/or in Phase II and enable such units to avoid making emissions reductions that title IV would otherwise require them to make. These allowances may thereby diminish the emissions reductions that Congress intended to be achieved by virtue of title IV. In sum, as explained in the November 18, 1993 preamble, the January 11, 1993 regulations transform the statutory substitution and reduced utilization provisions from provisions for facilitating and protecting anticipated emissions reductions under title IV into potential means of creating excess, new allowances that can be used to avoid such reductions. (58 FR 60953.)

Because the regulations provide alternative means (through substitution plans or reduced utilization plans) of creating excess, new allowances, the regulations are contrary to Congressional intent and sections 404(b) and (c) and 408(c)(1)(B) of the Act and therefore must be modified to eliminate both alternatives.

B. Under the January 11, 1993 Regulations, Entry of Phase II Units Into Phase I can Significantly Compromise the Emissions Reduction Goals of Title IV

The potential number of excess, new allowances created by substitution and compensating units under the January 11, 1993 regulations may be sufficient to compromise significantly the achievement of the emissions reductions intended by Congress under title IV. The Agency estimates that entry into Phase I of Phase II units that will benefit from becoming substitution or compensating units and that reduced emissions rates between 1985 and 1991 for economic or other reasons or were required by federal or State law as of November 15, 1990 to reduce emissions rates between 1985 and 1995 will create about 200,000 allowances per year in Phase I in excess of emissions without such entry.[2] *See* 58 FR 60953 and n. 4; and Calculation of Potential Impacts of Phase I Substitution Units, ICF Inc. at 5 (July 7, 1993). Thus, the current substitution and reduced utilization provisions will potentially result in the creation of excess, new allowances authorizing additional emissions of 1,000,000 tons of sulfur dioxide in all of Phase I.

Congress expected the emission limitations in title IV to result in annual SO_2 emissions reductions of 2.8 to 4.4 million tons in Phase I. Senate Rep. No. 101-228 at 327; Cong. Rec. S16980 (Oct. 27, 1990).[3] EPA estimates that the expected reductions by Phase I units alone during Phase I are about 2.4 million tons in 1995 and 1996 and about 3.5 million tons in 1997, 1998, and 1999. Memorandum from T. Larry Montgomery to Brian J. McLean (Oct. 15, 1993). As discussed above, the statutory language and legislative history demonstrate that Congress did not intend these reductions to be eroded by substitution or reduced utilization plans. Yet, under the current regulations, Phase I units can avoid some of these reductions by offsetting their emissions in Phase I with excess, new allowances resulting from such plans. The use of 200,000 excess, new allowances per year in Phase I will negate a significant portion (i.e., 6 to 8 percent) of estimated, expected reductions for Phase I units.

Alternatively, banking these new allowances for use in Phase II will diminish the intended emissions reduction impact of the 8.95 million ton cap established by Congress for Phase II. *See* 58 FR 60954–60955 (explaining the importance of the Phase II cap). The carryover and use of the excess, new allowances created by early entry of Phase II units into Phase I can result in emissions exceeding the cap for each of the first five years of Phase II by as much as 200,000 tons.

The magnitude of potential erosion of expected emissions reductions supports the Agency's conclusion, based on statutory language and legislative history, that Congress did not intend to allow substitution or compensating units to create allowances for pre-Phase II emissions reductions that would have been achieved in the absence of substitution and reduced utilization plans.[4] The Agency's conclusion is also supported by Congress' approach in sections 404(e), 405, and 410 of the Act. As discussed in the November 18, 1993 preamble (58 FR 60954), the fact that in those sections Congress carefully limited the ability of Phase II units to obtain additional allowances for pre-Phase II reductions strongly suggests that sections 404(b) and (c) and 408(c)(1(B) should not be interpreted to allow allowance allocations for all such reductions.

III. Modifications of the January 11, 1993 Regulations

A. Substitution Plans

The Agency is modifying the January 11, 1993 regulations concerning substitution plans by limiting the allowances allocated to a substitution unit to the baseline times the lesser of: the 1985 actual SO_2 emissions rate; the 1985 allowable SO_2 emissions rate; the greater of 1989 or 1990 actual SO_2 emissions rate; or the most stringent federal or State allowable SO_2 emissions rate for Phase I as of November 15, 1990, the date of enactment of title IV of the Act. In addition, the final regulations eliminate the language in the January 11, 1993 regulations providing that a Phase II unit that lacks any common owner or operator but has a common designated representative with a Phase I unit can, without anything more, be designated as a substitution unit.

1. Limiting the Allowances Allocated to Each Substitution Unit

The final rule limits the number of allowances allocated to each substitution unit by calculating the allocation using the lesser of the unit's 1985 SO_2 emissions rate or an SO_2 emissions rate that is reasonably representative of what would have been achieved without the substitution plan. Specifically, a substitution unit will be allocated allowances equal to baseline times the lesser of: the unit's 1985 actual SO_2 emissions rate; the unit's 1985 allowable SO_2 emissions rate; the greater of the unit's 1989 or 1990 actual SO_2 emissions rate; or the most stringent federal or State allowable SO_2 emissions rate as of November 15, 1990 applicable to the unit in 1995–99. The January 11, 1993 regulations consider only the unit's 1985 actual or allowable SO_2 emissions rate.

As discussed above, section 404(b)(5) requires that the substitution plan include a demonstration that the "reassigned tonnage limits [under the plan] will, in total, achieve the same or greater emissions reduction than would

[2] This is a conservative estimate of the potential for creation of excess, new allowances. Assuming that all 250 designated substitution and compensating units in existing permit applications are activated as substitution units for all of Phase I, about 385,000 excess, new allowances will be created per year under the January 11, 1993 regulations. Assuming all existing Phase II units (about 2,000 units) will become substitution units for all of Phase I, almost 1,000,000 excess, new allowances will be created per year in Phase I under the January 11, 1993 regulations. *See* Estimates of Allowances Impact of Proposed Permits Rule Revisions and Alternative Regulatory Scenarios at 3, 8, and 52 (Oct. 20, 1993) (comparing "totals" for allowance allocations under "existing" rule and "proposed" rule). The Agency's 200,000-allowance estimate reflects the assumption that only those units (about 200 to 300 units) with projected 1995 emissions lower than their 1985 level will be likely to become substitution units under the current regulations. *See* Calculation of Potential Impacts of Phase I Substitution Units at B-4 ("total" of units with "SO_2 decrease" under "CAT7") (July 7, 1993). That estimate also assumes that some allowances that will be created will result from reduced utilization and will be subject to surrender to EPA under §§ 72.91 and 72.92 of the regulations. *Id* at 7 and 9.

[3] Because, as discussed above, Congress did not intend the substitution and compensating unit provisions to create excess, new allowances, commenters erred in claiming that such allowances account for the 2.8 to 4.4 million ton range for estimated Phase I reductions in SO_2. Rather, the range reflected, *inter alia*, uncertainty over what emissions decreases or increases would occur at Phase II units that would not be subject to emissions limitations until Phase II. Because of the lack of emissions limitations on such units in Phase I, the Phase I emissions of these units and the impact on total Phase I reductions could only be projected.

[4] Thus, contrary to the assertion of some commenters, the Agency's modification of the current regulations is not based on circular reasoning. The statutory language and legislative history demonstrate that Congress did not intend for substitution or reduced utilization plans to result in fewer reductions than without the plans. The analysis that such plans under the January 11, 1993 regulations can result in about 200,000 excess, new allowances per year in Phase I shows the potential magnitude of the problem and supports today's modification of the regulations to ensure consistency with the statute.

have been achieved by the original affected unit and the substitute unit or units without such substitution." 42 U.S.C. 7651c(b)(5). The Agency interprets this provision to require that the plan achieve total reductions equal to or greater than both (i) the Table A unit's reduction obligation in Phase I and (ii) the reductions that the substitution unit would have made if it had not entered Phase I, including reductions made, or mandated by federal or State law adopted, prior to the passage of title IV.

The preamble of the January 11, 1993 regulations sets forth a different interpretation of section 404(b)(5) that the Agency concludes is erroneous. As EPA explained in the November 18, 1993 preamble (58 FR 60954–60955):

In the January 11, 1993 preamble, the Agency stated that any reductions in emissions rate that have been, or will be, made at the substitution unit after 1985 without the substitution plan (e.g., reductions for economic reasons or required by federal or State law) "will not have resulted from title IV" and so should "*not* be counted as reductions that would have occurred without the plan." 58 FR 3601 (emphasis added). The difficulty with this interpretation is that it appears to read out of section 404(b)(5) the requirement to ensure that a substitution plan does not negate reductions "that would have been achieved by * * * the substitute unit * * * without such substitution." 42 U.S.C. 7651c(b)(5). In the absence of the plan, the substitution unit would not be subject to title IV until Phase II. If only reductions required by title IV were considered under section 404(b)(5), the amount of reductions that would have been achieved by the substitution unit without the plan (i.e., the reductions in Phase I) would always be zero * * *. The reference to such reductions would therefore be meaningless. In interpreting the Act, it should not be presumed that Congress adopted meaningless language.

Some commenters on the November 18, 1993 proposal suggested a third interpretation of section 404(b)(5). They claimed that the provision addresses only situations where, as part of the substitution plan, allowances that would be allocated to the substitution unit are instead allocated by EPA to the Table A unit. Specifically, the commenters alleged that the terms "reassigned tonnage limits" and "such substitution" in section 404(b)(5) are synonymous and refer only to the "allocation of a number of allowances to the Table A unit in addition to those that the Table A unit would otherwise receive." Comments of UARG at 33 n. 54 and 34. Accordingly, it is argued that section 404(b)(5) requires only that the number of additional allowances that are allocated under the plan to the Table A unit cannot be greater than the number of allowances that are subtracted from the allocation that the substitution unit would otherwise receive under the plan.

The Agency rejects this interpretation, which is inconsistent with the substitution plans that the commenters themselves have submitted to the Agency and which would reduce section 404(b)(5) to a triviality. As the commenters noted, section 404(b) describes a substitution plan as "a proposal to reassign, in whole or in part, the affected [Table A] unit's sulfur dioxide reduction requirements to any other unit(s)" under the control of the owner or operator of the Table A unit. 42 U.S.C. 7651c(b) and Comments of UARG at 33. According to the commenters, such reassignment occurs only where allowances otherwise allocated to a substitution unit are instead allocated to the Table A unit. *Id.* at 34 and 40–1. This is allegedly the only circumstance to which section 404(b)(5) would apply.

If the commenters' interpretation were correct, then only those plans that actually provide for such an additional allocation of allowances to the Table A unit would be substitution plans, as defined by section 404(b). However, although § 72.41(c)(4)(ii) of the January 11, 1993 regulations provides the *option* to redistribute allowance allocations in this way, such redistribution is not required by § 72.41. Moreover, EPA has not received a single substitution plan for any units that includes such a redistribution of allowance allocations. *See* 58 FR 32667–32670 (June 11, 1993); 58 FR 34582 (June 25, 1993); 58 FR 38373–38375 (July 16, 1993); 58 FR 39543–39544 (July 23, 1993); 58 FR 40812–40813 (July 30, 1993); 58 FR 42065–42069 (Aug. 6, 1993); and 58 FR 43110 (Aug. 13, 1993) (summarizing the allowance allocations under the proposed plans, none of which included any redistribution of allowances from a substitution unit to a Table A unit). Under the commenters' approach, none of the substitution plans submitted to date are "proposals to reassign * * * reduction requirements" under section 404(b). Further, the commenters' interpretation of section 404(b)(5) would reduce that provision to a trivial requirement that EPA cannot give more additional allowances to the Table A unit than it takes from the substitution unit.[5]

When section 404(b)(5) is properly interpreted, these problems evaporate. The term "reassigned tonnage limits" refers to the total allowance allocations made, in every substitution plan, to the Table A and substitution units under the plan and not simply to redistributed allowances. Thus, section 404(b)(5) requires that each substitution plan must result in "the same or greater" reductions of sulfur dioxide emissions as would have been made by the Table A and substitution units without a substitution plan.[6] 42 U.S.C. 7651c(b)(5).

The Agency concludes that section 404(b)(5) must be interpreted to take into account, and avoid allocating allowances to the substitution unit for, reductions that would otherwise have been made at the substitution unit since 1985 in the absence of a substitution plan. The Agency maintains that there are two categories of reductions that would otherwise have been made and that therefore should be excluded from the allocation of allowances to substitution units: (1) emissions rate reductions that were made voluntarily, for economic or other reasons, by a substitution unit after 1985 and before enactment of title IV; and (2) emissions rate reductions by a substitution unit between 1985 and 2000 that were mandated by federal or State law as of the enactment of title IV.

a. 1989 or 1990 SO_2 emissions rate. With regard to the first category of emissions reductions, EPA is modifying the January 11, 1993 regulations to provide that substitution units will not be allocated allowances for voluntary emissions rate reductions made before enactment of title IV: i.e., reductions before title IV's enactment that were not mandated by federal or State law and that were made for economic or other reasons. To the extent a unit's emissions rate reductions are caused by economic or other factors that would have existed in Phase I even if the unit did not become a substitution unit, such reductions would have occurred without a substitution plan and therefore must be taken into account under section 404(b)(5) and excluded

[5] Apparently, EPA could, under the commenters' interpretation, allocate fewer additional allowances to the Table A unit than are subtracted from the substitution unit's allowance allocation.

[6] The commenters relied on Senate Report No. 101–228 at 307 and a floor statement by Senator Baucus (136 Cong. Rec. S16980 (daily ed. Oct. 27, 1990)) to support the claim that section 404(b)(5) requires consideration only of the emissions reductions that would be achieved by the Table A unit, and not those by the substitution unit, in the absence of the plan. Such reliance is misplaced because section 404(b)(5) explicitly requires that the emissions reductions at both the Table A and the substitution units without the plan be considered. 42 U.S.C. 7651c(b)(5).

from allowance allocations. In theory, any reductions made by a unit between 1985 and 1999 could potentially be in response to such factors and, if so, could be considered as reductions that would have occurred without the substitution plan.

The Agency maintains that there must be a bright line drawn to determine whether a unit's voluntary reductions in emissions rate would occur even if the unit were not a substitution unit. It would be difficult to make accurate case-by-case determinations, concerning a large number of units, as to whether the owners and operator of a particular unit took actions after 1985 to reduce its emissions rate in anticipation of the unit becoming a substitution unit. Such determinations would require analyzing economic and other factors that may be involved (e.g., fuel costs, the timing for retrofitting of pollution controls, and the regulatory benefits and risks of becoming a substitution unit), balancing the factors favoring or disfavoring action to reduce the emissions rate, and judging what the owners and operator would have done in the past concerning the unit's emissions in the absence of substitution plans.[7] *See* Comments of Environment Defense Fund and the Natural Resources Defense Council at 16 (submitted Feb. 10, 1994). Similar determinations would presumably have to be made for each approved substitution unit, and allowance allocations might have to be adjusted, each time the owners and operators of the unit take actions after approval of the substitution plan that reduce the unit's emissions rate in Phase I.

The Agency concludes that the best approach to developing a reasonable approximation of what a unit's emissions rate would be in Phase I in the absence of a substitution plan is to treat all voluntary emissions rate reductions after 1985 and through 1990 (the year in which title IV of the Act was passed) as reductions that would have occurred in Phase I in the absence of a substitution plan. Prior to enactment of the Clean Air Act Amendments of 1990, utilities had no reasonable expectation that emissions reductions would generate nationally tradable allowances under the Act. The reductions were not made in response to the availability of allowances under substitution plans. December 31, 1990 (rather than November 15, 1990, the specific date of title IV's enactment) is used as the cut-off point for determining what reductions that would have occurred without the plan because emissions rate data is available on a calendar year basis. Even though some reductions after 1990 perhaps would have occurred without the plan, it would be difficult to sort out, for a large number of units, the impact of the availability of substitution plans for the period after the substitution provision was enacted.

Further, reductions reflected in a unit's 1989 or 1990 SO_2 emissions rate will be treated as representative of reductions that would continue to be made up through 1999. In the November 18, 1993 proposal, the Agency proposed to use the 1990 actual SO_2 emissions rate as the measure of emissions reductions made before passage of title IV. The 1990 rate was proposed because, as the emissions rate closest to November 15, 1990, it is more likely to reflect all the reductions made prior to passage of title IV. The rate for an earlier year is less likely to reflect all reductions made before passage of title IV. However, several commenters expressed concern that a unit's emissions rate for a single year (i.e., 1990) might be unusually low and therefore unrepresentative of its emissions rate prior to the passage of title IV. These commenters suggested that, if post-1985 emissions rates are used, the Agency should use a formula that allows consideration of actual emissions rates for 1988, 1989, and 1990. *See* Comments of Utility Air Regulatory Group at 45 (submitted Feb. 10, 1994); Comments of Northern States Power Company at 6 (submitted Feb. 10, 1994). Other commenters claimed that the 1990 emission rate may be lower than the 1985 emission rate because of normal variability in the sulfur content of coal or in scrubber performance. They suggested a case-by-case determination of whether such variability accounts for the lower 1990 emissions rate.

Balancing these factors, the final rule uses the greater of the 1989 or 1990 actual SO_2 emissions rate to reflect pre-title IV emissions rate reductions. A unit's 1989 or 1990 emissions rate (which are the most recent, actual rates prior to the enactment of title IV) will be treated as representative of its emissions rate in Phase I in the absence of a substitution plan. This provides some flexibility to avoid using a single and perhaps unrepresentative year. All voluntary emissions rate reductions made after 1990 will be treated as reductions that would not otherwise have occurred.

Several commenters opposed the use of any post-1985 actual emissions rate in limiting allowance allocations to substitution units. Commenters argued the use of the 1990 actual emissions rate is arbitrary. Allegedly, this approach is arbitrary because it assumes that emissions-reducing actions that were taken before 1991 for economic reasons will not necessarily continue to be taken after passage of the Clean Air Act Amendments of 1990, which changed the economics of such actions. Commenters stated that utilities might redirect low sulfur coal from the potential substitution unit to another unit and burn higher sulfur coal at the former unit. They also suggested that when the lower sulfur coal contract expires, the utility might contract for higher sulfur coal.

There are several problems with these commenters' arguments. A reduction in a unit's 1989 or 1990 emissions rate from 1985 could be the result of several types of actions, including the addition of pollution control equipment or the use of low sulfur coal. To the extent that the reduction reflects a capital investment in pollution control equipment, it is reasonable to assume that the equipment will probably remain in place and continue to be used. Even where the reductions were achieved through the use of low sulfur coal, the use of such coal or switching to high sulfur coal requires, in many cases, capital investment in new equipment. This reduces the likelihood that emissions reductions made before enactment of title IV would be reversed after passage of title IV.

Moreover, in section 404(b)(5), Congress required EPA to ensure that the reductions achieved under each substitution plan be "the same or greater than" the reductions that would otherwise be achieved without the substitution plan. 42 U.S.C. 7651c. Because of the paramount importance apparently placed on the goal of achieving intended emissions reductions, Congress required the Agency to adopt an approach that would ensure no fewer reductions with substitution plans than without such plans but that could result in more reductions with than without the plans. In light of this statutory requirement and the difficulty of determining what reductions would have been made without substitution plans, the Agency concludes that the 1989 or 1990 actual emissions rate is a reasonable proxy for a unit's Phase I emissions rate without the substitution plan. To the extent that the Agency's approach of using 1989 or 1990 emissions rate overstates the reductions that would be achieved without the plan, the approach errs in a direction that ensures achievement of

[7] Thus, particularly where there are a large number of units involved, the Agency does not agree with those commenters that claimed that a showing that post-1990 reductions would not have occurred in the absence of a substitution plan would be "easily" evaluated. *Id.*

the paramount statutory objective and is consistent with section 404(b)(5).

In contrast, commenters' preferred alternative—using only 1985 actual or allowable emissions rates—would guarantee, in some cases, violation of the statutory objective of no fewer reductions with, than without, the plan. One particularly graphic example of that result is where a Phase II unit is voluntarily and permanently shutdown between 1985 and 1991 and is brought into Phase I as a substitution unit. Without a substitution plan, the unit would emit no sulfur dioxide and receive no allowances in Phase I. With the plan, the unit would still have no emissions but would be allocated a significant number of new allowances reflecting its 1985 emissions and other units could use the newly created allowances to authorize emissions that would not otherwise have been allowed. *See, e.g.*, 58 FR 38375 (noticing permit application with plan designating, as substitution units, Poston units 1, 2, and 3, which were permanently shut down in 1987). The Agency's use of the most recent actual emissions rates prior to passage of title IV is a reasonable approach to achieving the purposes of section 404(b)(5).

Commenters also argued that the Agency's approach penalizes those utilities that were "environmentally * * * progressive" and will discourage voluntary emissions reductions in the future. Comments of the Class of '85 Regulatory Response Group at 8 (submitted Feb. 10, 1994). However, each utility that made emissions reductions at Phase II units after 1985 and before the date (January 1, 2000) such reductions are required under title IV already benefits in Phase II of the Acid Rain Program, during which the units are allocated allowances reflecting in part the 1985 emissions rate. *See* Comments of Northern States Power Company at 3 (noting that allocations to most of the utility's units in Phase I and Phase II exceed 1990 emissions levels). The issue here is whether, if such a utility elects to bring selected Phase II units into Phase I, the utility should receive additional benefit (in the form of extra allowances for pre-title IV reductions) that violates section 404(b)(5) of the Act. The Agency believes that the approach in the final rule is a reasonable implementation of section 404(b)(5).

b. Most stringent federal or State SO_2 emissions limitation. In addition to limiting a substitution unit's allowance allocation using the unit's 1989 or 1990 SO_2 emissions rate, EPA is also modifying the January 11, 1993 regulations to provide that a substitution unit will be allocated allowances based on an emissions rate that does not exceed the most stringent SO_2 emissions limitation imposed in Phase I by federal or State law, as of November 15, 1990. By definition, emissions rate reductions that were mandated prior to title IV's enactment and that are required regardless of whether the unit is a substitution unit are reductions that would have occurred in the absence of the plan.

The agency recognizes the difficulty of determining whether any particular federal or State emissions reduction requirement (whether a tightening or a loosening of emissions limitations), adopted after title IV's enactment, would have been adopted in the absence of substitution plans under title IV.[8] This is similar to the problem of determining whether voluntary emissions rate reductions after 1990 would have been made without a substitution plan, except that, with regard to federal or State emissions limitations, political factors favoring or disfavoring imposition of the limitations would have to be weighed. Consequently, the Agency maintains that a bright line, based on title IV's date of enactment, should be established and that emissions rate reductions that were mandated by federal or State law adopted after November 15, 1990 should not be treated as reductions that would otherwise have occurred. As explained in the preamble of the November 18, 1993 proposal (58 FR 60956), the most stringent allowable rate for purposes of substitution-unit allowance allocations will be the most stringent rate as of November 15, 1990 after conversion to pounds per mmBtu but without any annualization.

Some commenters argued that the Agency should distinguish between federal emissions limitations and State emissions limitations and consider only federal limitations in allocating allowances to substitution units. They alleged that it is unfair to "penalize" utilities in States "tak[ing] the lead in controlling air emissions" and that title IV references federal, but not State, emissions limitations. Comments of Dairyland Power Cooperative at 2 (submitted Jan. 26, 1994). However, section 404(b)(5) requires that emissions reductions with the substitution plan be no less than reductions without the plan and does not distinguish between reductions without the plan that are due to State law from those due to federal law. Thus, contrary to the commenters, there is no basis for considering only federal, and ignoring State, emissions limitations in applying section 404(b)(5). Further, the Agency reiterates that:

> [S]ince reliance on substitution plans is optional and the use of the most stringent allowable rate (in conjunction with the 1985 actual or allowable rate and the [1989 or] 1990 actual rate) to allocate allowances under such plans is necessary to meet statutory emissions reduction goals, it is difficult to see how such use of the most stringent allowable rate could be viewed as unfair to utilities located in States that mandated reductions. This approach simply prevents the creation of excess, new allowances and thereby ensures that reductions mandated by such States are not used to increase emissions elsewhere above the levels that title IV was intended to achieve.
> 58 FR 60956.

Using federal or State emissions limitations to limit a particular substitution unit's allowance allocation raises certain questions, particularly where some emissions limitations are not unit specific. For example, under some State laws (e.g., the acid rain laws for Massachusetts and Wisconsin), a utility has a maximum average emissions rate for its units in the State. Under other State laws (e.g., for New Hampshire and Minnesota), a utility has a total tonnage emissions cap for all its units in the State. Maximum average emissions rates or maximum total tonnage limits allow utilities the flexibility to exceed such maximum rates or limits at individual units so long as the maximum rates or limits are met on a utility-wide basis. Since individual units may exceed such maximum rates or limits, the Agency concludes that it should not treat the maximum rates or limits as the most stringent limitation for each individual unit. However, while utility-wide limitations provide some flexibility, such limitations impose bounds on the emissions of individual units, albeit bounds that depend on the emissions from other units owned or operated by the same utility. There is no basis for ignoring the fact that a unit may have to make emissions reductions because of a

[8] In contrast, State emissions limitations adopted prior to passage of title IV do not raise the same question about whether they would have been adopted in the absence of title IV. Such emissions limitations, e.g., the Massachusetts acid rain law passed in 1985, were in fact adopted in the absence of any federal acid rain program. The Massachusetts statute included a provision stating that the Massachusetts legislature intended that reductions made under that statute be credited to Massachusetts' share of required reductions if a federal acid rain program was established in the future. Massachusetts, Acts of 1985, Chap. 590 § 9. Some commenters challenged, as contrary to the intent of the Massachusetts law, the use of the Massachusetts emissions limitations to limit allowance allocations under title IV. However, Congressional intent, not the intent of the Massachusetts legislature, is relevant to interpreting title IV.

utility-wide limitation, just as it may have to reduce emissions because of a unit-specific limitation.

Consequently, the final revised rule provides that the Agency will develop a method for using both the unit-specific and non-unit-specific emissions limitations to limit the allocation of allowances to a substitution unit. This method will not treat non-unit-specific limitations as if they were unit specific and will not allow allocation of allowances for reductions that were necessary to meet non-unit-specific limitations. Because there are significant differences among State laws and the manner in which they express non-unit-specific emissions limitations, the final revised rule gives the Agency the authority to develop this method on a case-by-case basis for each proposed substitution unit. This approach will give the Agency the flexibility to take account of variations among States and will allow interested parties an opportunity, e.g., in proceedings on individual permits, to comment on the method that the Agency proposes to use with regard to a particular non-unit-specific limitation.

Several commenters made specific recommendations concerning the method that EPA should use to apply the unit-specific limitations under Wisconsin's acid rain law. Under the Wisconsin law, each major utility that generates electricity in the State must achieve an annual average sulfur dioxide emissions rate that does not exceed 1.2 lbs per mmBtu starting in 1995 from all fossil fuel-fired boilers under the utility's ownership or control. A Wisconsin utility that meets certain requirements may trade emissions with another Wisconsin utility. One utility accepts—and adds to its annual emissions—emissions from another utility, which subtracts those emissions from its annual emissions and thereby reduces its annual average emissions rate in order to meet the utility-wide limit. Some commenters suggested that, in initially allocating allowances to substitution units in Wisconsin, EPA consider only those Federal and State limitations that are expressed as unit-specific limitations and not the utility-wide limits under Wisconsin's acid rain law. These commenters supported an end-of-year review in which each Wisconsin utility will have to demonstrate whether, if the allowances allocated to its substitution units in Wisconsin are treated as emissions by those units, the utility will still be in compliance for that year with 1.2 lbs per mmBtu limit. In this demonstration, the utility will sum the actual annual emissions of each boiler owned or controlled by the utility, except in the case of a substitution unit where the allocated allowances will be used. Where emissions were traded for the year, traded emissions will be subtracted by one utility from, and added by another utility to, the sum of emissions and allowances. The total will be divided by the sum of the annual mmBtu utilization of all the boilers involved. To the extent that the result exceeds 1.2 lbs per mmBtu, the utility will be required to surrender, and EPA will deduct, allowances allocated to the substitution units for that year. No commenters supported imposing limits on the ability to transfer the substitution unit's allowances prior to the end-of-year review. However, one commenter opposed the use of any end-of-year review to apply the Wisconsin utility-wide emissions limit.

The Agency is not deciding in the instant rulemaking what particular procedure will be used for applying non-specific emissions limitations and whether to adopt an approach involving end-of-year review. However, such review may be the best way to take account of the flexibility that the Wisconsin acid rain law and other State provisions provide to individual units in meeting State emissions limitations. The final revised rule, therefore, allows EPA to decide on a case-by-case basis, e.g., in individual permit proceedings on proposed substitution units, whether to require end-of-year review to apply non-unit-specific emissions limitations. The final revised rule also authorizes the Agency to require allowance surrender, and make allowance deductions, by the allowance transfer deadline as a result of such review.[9]

The Agency maintains that it is unnecessary to impose, pending any end-of-year review, limitations on the ability to transfer a substitution unit's allowances. The risk that a substitution unit will not have allowances in its Allowance Tracking System account to cover the deduction is small. As of the allowance transfer deadline, the unit's account must contain, in any event, sufficient allowances to cover its emissions for the prior year. The deduction of allowances resulting from the substitution unit's end-of-year review must be made before the Agency determines whether the unit's emissions exceeded its available allowances. Consequently, the failure of the substitution unit to have sufficient allowances to cover any deduction resulting from the end-of-year review will constitute a violation of § 72.41 (and so the Clean Air Act itself) and will result in excess emissions and trigger excess emissions penalties. Not only are limitations on transferability unnecesssary, but also they would reduce the compliance flexibility that Congress intended to provide through substitution plans. The final rule therefore does not impose any limits of transferability, pending any end-of-year review.

In sum, the Agency concludes that a substitution unit should be allocated allowances based on the lesser of four emissions rates for the unit: 1985 actual SO_2 emissions rate; 1985 allowable SO_2 emissions rate; the greater of 1989 or 1990 actual SO_2 emissions rate, or the most stringent Federal or State allowable SO_2 emissions rate applicable in 1995–99 as of November 15, 1990. The first two emissions rates are set forth in section 404(b)(2) of the Act. The latter rates are added in order to ensure, in accordance with section 404(b)(5), that a substitution plan will result in at least the same amount of reductions that would have occurred without the plan.

This approach requires the submission to EPA of data on the 1989 and 1990 emissions rates and the emissions limitations for 1995–99. For the reasons set forth in the November 18, 1993 preamble (58 FR 60956), the Agency maintains that section 404(b) provides adequate authority to require submission of this data and to use the data to calculate the allowance allocation under the plan.

c. Baseline. Under the final revised rule, a substitution unit's allowance allocation is calculated by multiplying the lower of the above-discussed emissions rates by the baseline, which reflects 1985–87 utilization. The January 11, 1993 regulations used baseline (and only the 1985 actual or allowable SO_2 emissions rate) to calculate the allowance allocation. In the November 18, 1993 preamble, the Agency discussed the options of basing allocations on utilization at the time a permit application is submitted or requiring utilities to project what future utilization of the substitution units would be in Phase I without the substitution plan and using the projected utilization to allocate allowances. No commenters supported the use of projected utilization, and those that specifically addressed the matter preferred continued use of baseline. For the reasons set forth in the

[9] Contrary to one commenter's claim, the fact that section 402(3) of the Act defines "allowance" as "an authorization * * * to emit * * * one ton of sulfur dioxide" in no way bars the imposition of a requirement, consistent with other sections of the Act, to surrender allowances. 42 U.S.C. 7651a(3). Section 403(f) of the Act states that an allowance allocated under title IV is "a limited authorization to emit sulfur dioxide in accordance with the provisions of this title." 42 U.S.C. 7651b(f).

preamble (58 FR 60956–57), the Agency concludes that a substitution unit's baseline should continue to be used to calculate the allowance allocation.

2. Limiting the Number of Substitution Units

The Agency rejects modifications of the January 11, 1993 regulations making upfront approval of the designation of substitution units and allocation of allowances to such units contingent on an end-of-year review of the need for such units for each year that the plan was in effect. Under such an approach, the Agency would allow only those designations of substitution units that actually proved to be needed. No commenters supported that approach.

Because allowance allocations for substitution units are limited as discussed above, the Agency concludes that requiring end-of-year review of the need for substitution units and thereby limiting the number of such units is unnecessary. If a substitution unit is not allocated allowances for emissions rate reductions that would have occurred without a substitution plan, then the unit will use up all or most of its allocated allowances unless the unit made new emissions rate reductions that would not otherwise have been made. To the extent that a substitution unit frees up allowances by making such new emissions rate reductions, section 404(b)(1)(5) is not violated. *See* 58 FR 60957. In short, because today's final rule prevents any substitution unit from creating new, excess allowances, there is no need to impose further requirements limiting the number of substitution units.

3. Requirement That the Substitution Unit Be Under Control of the Table A Unit's Owner or Operator

The January 11, 1993 regulations provide that the statutory requirement that the substitution unit be under the control of the Table A unit's owner or operator is satisfied where such units have only a common designated representative. This was based on the determination that a common designated representative qualifies, in such cases as an operator. 40 CFR 72.41(b)(1)(i); *see also* 42 U.S.C. 7651c(b). In the November 18, 1993 preamble, the Agency proposed to reverse its interpretation that having a common designated representative, without more, meets this statutory requirement and to revise the regulations accordingly. 58 FR 60957–60958. The Agency today adopts the reasoning, set forth in the November 18, 1993 preamble (*Id.*) and in the preamble of the Acid Rain regulations on nitrogen oxides (59 FR 13554–55), that a designated representative is not, merely by holding that position, also an operator.

In the preamble of the January 11, 1993 regulations, the Agency stated that, under some circumstances, a designated representative's "duties and level of responsibility can be equivalent to that of an operator." 58 FR 3600. One such case, identified by the Agency, was where a designated representative represents multiple sources participating in a substitution plan and otherwise lacking the same owner or operator. In that case, the designated representative's responsibilities are allegedly "broad enough to bring him or her within the definition of operator." *Id.* As discussed in the November 18, 1993 proposal and the March 22, 1994 final NO_X rule, a designated representative's responsibilities in a multi-source substitution plan are not actually any broader or more complex than they are under other compliance options. Therefore, there is no basis for treating a designated representative in such a substitution plan any differently than a designated representative under any other compliance option. In all such cases, a designated representative is not an operator. The final revised rule reflects this conclusion by eliminating language from the January 11, 1993 regulations that provided that units with a common designated representative, and nothing more, could participate in a substitution plan.

Some commenters note that, although § 72.41(b)(1)(i) requires that the substitution and Table A units have "the same owner or operator" (40 CFR 72.41(b)(1)(i) (1993)), section 404(b) itself states that the substitution unit must be "under the control of the owner or operator" of the Table A unit. They argue that, in implementing section 404 (b) and (c), the Agency should focus on whether there is such control. They suggest that the ownership of the units is not necessarily determinative of whether the control requirement is met. They allege that, on one hand, where the units have multiple owners only one of which is in common, the control requirement may not be met. On the other hand, where the units lack the same owner or operator, the control requirement allegedly may be met through contractual arrangements under which the owner and operator of the substitution unit commit, *inter alia*, to make emissions reductions and deliver allowances to the owner and operator of the Phase I unit.

In this final rule, the Agency is not addressing these additional issues concerning under what circumstances a proposed substitution unit is considered to be under the control of the owners or operator of a Phase I unit. EPA is addressing these issues, and the related comments, in a separate direct final rule in this **Federal Register**. In order to preserve these issues for resolution, the Agency is adopting, in today's final rule, the statutory language requiring that the owner or operator of the Phase I unit "control" the substitution unit that it designates.

4. Other Changes

The Agency has adopted several other minor changes to clarify the current § 72.41. For example, as discussed above, a substitution plan may distribute allowances between the substitution unit and the Table A unit. The final rule makes it clear in § 72.41(c)(4)(ii) that, where there is more than one Table A unit in a plan, allowances may be distributed from a substitution unit only to the Table A unit that designated that substitution unit. The final rule also eliminates the superfluous, but potentially confusing, final sentence in that section of the January 11, 1993 rules because the sentence simply repeats the limitation in § 72.41(c)(3)(ii) on the total number of allowances available under a substitution plan. *See* 40 CFR 72.41(c)(4)(ii) (1993).

B. Reduced Utilization Plans

The January 11, 1993 regulations implementing substitution and reduced utilization plans pose similar problems concerning the creation of excess, new allowances. However, because section 408(c)(1)(B) of the Act (unlike sections 404(b) and (c)) specifies the formula for allocating allowances, the Agency is adopting a different approach in modifying the requirements for compensating units than the one adopted today for substitution units. In order to ensure that reduced utilization plans are used as a means of accounting for emissions from load shifting from Phase I units and not as a method of creating excess, new allowances through early entry of Phase II units into Phase I, the Agency must limit the circumstances under which Phase II units can become compensating units.

In the November 18, 1993 notice of proposed rulemaking, the Agency suggested two options for limiting the designation of compensating units: the first option requiring that the compensating units be actually needed to compensate for reduced utilization and involving an end-of-year review of need; and the second option limiting up-front the category of units that can qualify to become compensating units.

The Agency is today rejecting the first option and is adopting the second option with some modifications.

1. Limiting the Category of Units That Can Qualify as Compensating Units

Under the option (Option 2 in the November 18, 1993 proposal) adopted today with some changes, the category of units that may be designated as compensating units is limited to those units whose designation cannot create excess, new allowances. The final revised rule provides that a unit can be designated as a compensating unit only if (1) the unit's baseline multiplied by the lesser of the unit's 1985 actual or allowable SO_2 emissions rate does not exceed (2) the baseline multiplied by the lesser of (i) the greater of the unit's 1989 or 1990 actual SO_2 emissions rate or (ii) the unit's most stringent federally enforceable or State enforceable SO_2 emissions limitation for SO_2 for 1995–99 as of November 15, 1990 plus (iii) the lesser of 10 percent of the tonnage calculated under (1) or 200 tons.

Consistent with its conclusions concerning substitution units, the Agency maintains that excess allowances may be created by the designation, as a compensating unit, of any Phase II unit whose baseline, multiplied by what its annual SO_2 emissions rate in Phase I would be in the absence of the designation, is less than the annual allowances allocated to the unit as a compensating unit. Even if such a Phase II unit increases its own generation to provide compensating generation, the unit may be able to use its own allowance allocation to cover its own emissions without making any more emission rate reductions than it would have otherwise made. In addition, the unit may have extra allowances to transfer, sell, or bank for future use. In order to prevent the creation of excess, new allowances, such units will not be allowed to be designated as compensating units.

For the reasons discussed above, the Agency concludes that excess, new allowances are created when Phase II units entering Phase I (e.g., compensating units) are allocated allowances for emissions rate reductions made, or mandated by federal or State law adopted, before passage of title IV. The general approach in the final rule is to bar, from becoming compensating units, those units that would otherwise receive such allocations if they were compensating units. Units that qualify as compensating units will be allocated allowances under the formula in section 408(c)(1)(B), i.e., baseline times the 1985 actual or allowable emissions rate.[10]

Contrary to some commenters, section 408(c)(1)(B) does not require the Administrator to approve whatever units a utility designates as compensating for reduced utilization. The Administrator must approve only those compensating-unit designations that are consistent with the purposes of title IV. 42 U.S.C. 7651h(c)(2). Section 408(c)(1)(B) does not expressly require the Administrator to consider a unit's 1989 or 1990 actual emissions rate or its most stringent emissions limitation. However, in reviewing proposed compensating units using these factors, the Agency is implementing section 408(c)(1)(B) in a way that precludes "a pattern or practice"—i.e., designation of compensating units that would receive excess, new allowances—"that is counter to the intent of section 404 and * * * title [IV of the Act]." Senate Rep. 101–228 at 334.

This approach is similar to that adopted with regard to substitution units except that, while the final rule allows units to become substitution units and adjusts their allocations, the final rule completely bars certain units from becoming compensating units. Consistent with the provisions concerning substitution units, the provisions for compensating units use the greater of the unit's 1989 or 1990 emissions rate as reasonably reflecting voluntary emissions reductions made before passage of title IV. Similarly, the provisions for substitution units and the provisions for compensating units take the same approach (including the treatment of non-unit-specific emissions limitations) to using the most stringent federal or State emissions limitations. *See* section III(A)(1)(b) of this preamble.

However, because some units could otherwise be completely barred from becoming compensating units because of very small differences (e.g., due to normal variability in coal quality) between their 1985 emissions and their actual or mandated emissions as of the passage of title IV, the Agency is building some extra flexibility into the provisions governing compensating units. The final rule allows the designation of compensating units whose baseline times the 1985 emissions rate is greater by only a very small amount (i.e., the lesser of 10 percent or 200 tons) than their baseline times the lesser of their 1989 (or 1990) emissions rate or their most stringent emissions limitation for Phase I. The flexibility band is measured in tons of emissions in order to ensure that the potential for creating excess, new allowances is restricted. Further, the flexibility band is also limited as a percentage of 1985 emissions because the band must apply to all potential compensating units, which can vary significantly in size and thus in total emissions. Using only a percentage limit or only a specific tonnage would have an inconsistent impact on units of different sizes.

Because of the inherent unreliability of projected utilization figures (discussed above in section III(A)(1)(c) of this preamble), baseline, not projected utilization, will be used to determine whether a unit qualifies as a compensating unit. If a utilization projection less than baseline were used to determine that a unit qualified as a compensating unit but subsequently the unit had a higher actual utilization in Phase I that would have otherwise disqualified the unit, the unit could create excess, new allowances.

In order to be approved, the designation of a compensating unit, of course, must meet the requirements in the January 11, 1993 regulations for reduced utilization plans as well as the additional requirement imposed in today's final revised rule. After determining that a particular proposed compensating unit meets all these upfront requirements, the Agency will approve the designation and allocate allowances for the unit. The Agency will not conduct any end-of-year review of the need for the compensating unit.

If a designated representative of a Phase I unit has no Phase II unit that will provide compensating generation and that meets all the upfront requirements for designation, the designated representative will not be required to submit a reduced utilization plan designating a compensating unit. The allowance surrender provisions in §§ 72.91 and 72.92 will continue to apply.

2. End-of-Year Review of the Need for Compensating Units

Under the rejected option (Option 1 in the November 18, 1993 proposal), units would have been allowed to remain as compensating units and would have retained allocated allowances only where the compensating units were actually needed to account for reduced utilization. *See* 58 FR 60959–60961. The Agency proposed in Option 1 to modify the reduced utilization provisions by granting upfront approval of a reduced utilization plan with compensating units but making approval contingent

[10] Thus, despite the claim of some commenters, Option 2 of the proposal does not change the allocation formula, which applies once it is determined that a unit qualifies as a compensating unit.

on an end-of-year determination by the Administrator that each compensating unit was needed for the year. A unit designated as a compensating unit would have become a Phase I unit and would have been allocated allowances upon upfront approval of the reduced utilization plan. However, a compensating unit would not have been allowed to transfer allowances allocated for any given year in Phase I unless and until an end-of-year determination of need was made for that unit for that year. If the unit was not shown to be needed, the unit would have been retroactively de-designated for the year and the allowances allocated for the year would have been deducted.

Under Option 1, a unit could be deemed, in the end-of-year review, to be needed as a compensating unit only for years in which: the Phase I unit actually had utilization below baseline; the Phase I units in the initial Phase I unit's dispatch system actually had total net utilization below the sum of their baselines after taking account of all sulfur-generation acquired by the dispatch system; and the proposed compensating unit actually provided compensating generation to that dispatch system. Further, the Administrator would determine how much compensating generation each compensating unit proposed for any Phase I unit potentially could have provided. The only compensating unit designations that would be allowed for any Phase I units in the dispatch system would be designations of compensating units whose potential excess generation would have been necessary to meet the potential need for compensating generation for the dispatch system as a whole.

The Agency is rejecting Option 1 because Option 2 is a simpler approach that ensures that, consistent with title IV and Congressional intent, compensating units cannot be used to create excess, new allowances. In contrast to Option 2, Option 1 would require designated representatives to make complicated end-of-year demonstrations of need, summarized above, and EPA to review and evaluate those demonstrations. Trading of allowances allocated to compensating units would be inhibited in that such trading would be barred pending completion of the Agency's review.[11] Further, while Option 1 would reduce the number of compensating units and thus the total amount of excess, new allowances that they could create, that option would not entirely eliminate the problem: those compensating units meeting the requirements of Option 1 could still create some excess, new allowances. Finally, the vast majority of commenters supported the use of Option 2 over Option 1.

3. Reporting and Allowance Surrender

The November 18, 1993 proposal included a number of changes —both substantive and nonsubstantive changes—to §§ 72.43 and 72.91 concerning reporting and allowance surrender requirements. 58 FR 60961-60962 (describing these changes). These changes are included in the final revised rule.

Commenters addressed only two of these changes. Under the proposal and the final revised rule, where a sulfur-free generator is designated outside a unit's dispatch system, the designated representative must submit, as part of the reduced utilization plan, the contractual agreements governing the "acquisition" of electricity by the unit's dispatch system from that generator. In addition, where a shift of generation from any designated sulfur-free generator (whether the generator is within or outside the dispatch system) is claimed, the designated representative must document that at least the amount claimed to have been shifted was actually "acquired" by the unit's dispatch system from the generator. The January 11, 1993 regulations referred to the contractual agreements governing and documentation concerning the "purchase", rather than the "acquisition", of electricity from sulfur-free generators. *See* 48 FR 3672 and 3682 (§§ 72.43(c)(4)(iv) and 72.91(a)(6) (1993)). Commenters supported this change adopted in the November 18, 1993 proposal. Some sulfur-free generators have multiple owners and may be owned in part by the unit's dispatch system. In such cases, the unit's dispatch system may not acquire electricity from the generator through a "purchase" but rather may acquire the electricity based on its ownership share. Further, it is important to ensure that multiple owners of sulfur-free generators claim only their respective shares of the sulfur-free generation. Consequently, the Agency is requiring documentation concerning the "acquisition," which encompasses not only "purchases" (as under the January 11, 1993 rule) but also acquisitions based on ownership. Further, the requirement to document actual acquisition applies to all designated sulfur-free generators.

One commenter claimed that the documentation required, under the proposal, for acquisition of sulfur-free generation is more stringent than necessary. The commenter noted that, under the proposal, the designated representative must demonstrate that electricity was actually acquired from "a particular sulfur-free generator." Comments of Oglethorpe Power Corporation at 7. Allegedly, it is "extremely difficult to trace energy back" to the sulfur-free generator. *Id.* The commenter further alleged that requiring that "a unit power or similar power sale agreement" govern the acquisition will result in "significant regulatory or other approval delays." *Id.* at 6. The commenter suggested that, instead of these requirements, the Agency require that the designated representative of the Phase I unit simply obtain the consent of an owner of the sulfur-free generator to claim, for purposes of the reduced utilization plan, some or all of that owner's share of generation from the sulfur-free generator. In order to ensure that the designated representative does not make such claims without actually getting the consent of the generator-owner, the commenter urged that EPA require that a copy of any reduced utilization plan involving a sulfur-free generator be given to all owners of the generator and the designated representative of the Phase I unit certify to EPA that the necessary consent was obtained. *Id.* at 5.

Under the commenter's approach, a Phase I unit would be relieved of the obligation to surrender allowances simply because it obtained the consent of an owner of a sulfur-free generator to "claim" some of that owner's electricity from the generator. As explained by the commenter, there would not have to be any actual acquisition of electricity by the dispatch system of the Phase I unit from the sulfur-free generator. However, the rationale for allowing the Phase I unit to avoid surrendering allowances if it designates a sulfur-free generator is that the Phase I unit is replacing the reduction in its own generation below its 1985–87 level with electricity from a source (i.e., a sulfur-free generator) that does not emit any sulfur dioxide when producing that electricity. To the extent the Phase I unit replaces its own reduced generation with electricity from units that emit sulfur dioxide in the process, allowances must be surrendered in order to account for the emissions consequences of the reduced utilization of the Phase I unit. Otherwise, the Phase I unit could bank its unused allowances "notwithstanding

[11] Because the Agency is rejecting all the limitations, discussed in the November 18, 1993 proposal, on the trading of allowances allocated to compensating or substitution units, the Agency has decided not to adopt any revisions to § 73.52 in the Allowance System rule.

the fact that actual emissions reductions had not been paid for or achieved" at that unit. 56 FR 63019.

The Agency recognizes that the complexity of the movement of electricity through interconnected transmission and distribution systems make it difficult to determine precisely the source of compensating generation. 56 FR 63023. That does not mean that all efforts, in the allowance surrender procedure, to reflect actual electricity transactions and to approximate resulting emissions should be abandoned. Under the commenter's approach, "paper" claims to sulfur-free generation that may have no actual, underlying energy transactions could be used to avoid allowance surrender. Such an approach would run contrary to the rationale for allowing the designation of sulfur-free generators and therefore is rejected.

Thus, the final revised rule includes the requirements that the designated representative of the Phase I unit submit: Contractual agreements that expressly provide for the acquisition of electricity by the unit's dispatch system from the designated sulfur-free generator outside the dispatch system, which generator must be identified in the agreements; and documentation that such acquisition from the identified generator actually took place. (Similarly, to ensure that claims of compensating generation are based on actual transactions, the same approach is taken for compensating units outside the dispatch system. *See* 58 FR 60961 (proposing parallel treatment of sulfur-free generators and compensating units).)

In light of these requirements, commenter's concern—that Phase I units lacking a common owner with a sulfur-free generator may claim to have acquired from the generator electricity that is actually sulfur-free generation retained by an owner of the generator—is misplaced. A sulfur-free generator can be designated only by those Phase I units that meet certain requirements. A Phase I unit whose dispatch system includes the generator may designate that generator.[12] If the generator is outside the dispatch system of a Phase I unit, the Phase I unit may designate the generator if the dispatch system has a contract specifically providing for the acquisition of electricity from the particular generator. A contact to purchase power from the dispatch system of an owner of the sulfur-free generator, where the sulfur-free generator is not specified as the source of the power, is not sufficient. If the dispatch system of the Phase I unit has a contract specifically to purchase power generated at the sulfur-free generator and the contract is with a third party that is not an owner of the generator, the designated representative must show that the third party in turn has an agreement with an owner of the generator specifically to purchase power from the generator. Further, § 72.91(a) (5) and (6) require that the designated representative document the amount of power actually acquired from the sulfur-free generator and that the designated representatives of all Phase I units claiming generation from the same generator must agree on apportionment of the available generation. It is difficult to see how a Phase I unit could take credit for electricity legitimately claimed by an owner of the sulfur-free generator. Consequently, it is unnecessary to impose the additional requirements suggested by the commenter.

IV. Applicability of Rule Revisions to Existing Permit Applications

In the November 18, 1993 proposal, the Agency requested comment on how to address any reliance by owners and operators on the January 11, 1993 regulations. The Agency noted that it had proposed in draft Acid Rain permits to approve for 1995, under the January 11, 1993 regulations, those substitution plans and those reduced utilization plans with compensating units that EPA determined to be in compliance with those regulations. 58 FR 60962. In a subsequent extension of the period for comments on the November 18, 1993 proposal, the Agency requested comments on whether any of the allowances allocated to substitution or compensating units under the January 11, 1993 regulations should be returned to EPA at some future time. 59 FR 3660 (Jan. 26, 1994).

In the November 18, 1993 proposal, it was also noted that, in the draft permits, EPA had proposed to defer action on those compliance options with regard to 1996–1999 pending completion of the instant rulemaking. 58 FR 60962–60963. In notices of draft permits, the Agency had stated that it intended to take this approach for all substitution and reduced utilization plans submitted before July 16, 1993 but that, with regard to such plans submitted on or after July 16, 1993, it intended to defer action for all of Phase I on those compliance options until completion of the rulemaking. 58 FR 38371 (July 16, 1993); 58 FR 39542–39543 (July 23, 1993); 58 FR 40812 (July 30, 1993); 58 FR 42065 (Aug. 6, 1993); 58 FR 43107 (Aug. 13, 1993).

The Agency had explained in draft permits, notices of draft permits, and the November 18, 1993 proposal that it was taking the position that it had the authority under the January 11, 1993 regulations to defer action on compliance options. *See, e.g.*, 58 FR 60963. Nevertheless, the Agency proposed, in the November 18, 1993 notice of proposed rulemaking, to add language to §§ 72.62 and 72.82 of the January 11, 1993 regulations "making this authority more explicit." *Id.*

However, the Agency concludes that it is no longer necessary to defer action for any period on any substitution or reduced utilization plans that have been submitted. The Agency has already issued direct final permits addressing these plans for all years during 1995–1999 for which the plans were proposed. *See, e.g.*, 59 FR 37755 (July 25, 1994); 59 FR 38454 (July 28, 1994); 59 FR 39339 (Aug. 2, 1994); and 59 FR 39767 (Aug. 4, 1994). Most of the permits automatically became final. Significant, adverse comment was received on several permits, which were reproposed and have now been issued in final form. *See* 59 FR 49395–49396 (Sept. 28, 1994). As provided in the May 4, 1994 settlement, the substitution and compensating units designated in the plans are allocated allowances in Phase I under settlement provisions consistent with today's final revised rule and receive for one or two years any additional allowances (referred to, in the settlement, as "excess" allowances) that would be provided under the January 11, 1993 regulations. Consistent with the May 4, 1994 settlement, allowances equal to the number of additional allowances allocated for one or two years will be deducted from a future year subaccount in the unit's Allowance Tracking System account.

Consequently, the Agency is withdrawing its position, set forth in draft permits, notices of draft permits, and the November 18, 1993 proposal, that it has the authority under the January 11, 1993 regulations to defer action on compliance options. The Agency is taking no position at this time on whether it has such authority. Further, under these circumstances, the Agency is not adopting the revisions to §§ 72.62 and 72.82 as proposed on November 18, 1993. The comments that were submitted on these proposed revisions and on the Agency's authority to defer action on compliance options

[12] No contract to acquire power from the sulfur-free generator is required if the generator is in the Phase I unit's dispatch system. Since a given sulfur-free generator can be included in only one dispatch system, Phase I units in any other dispatch system must have such a contract in order to desigate the generator.

are therefore no longer relevant and require no response at this time.

Moreover, the Agency is not addressing, in this rulemaking, questions concerning whether and how to apply today's final revised rule to permit applications submitted to the Agency prior to the effective date of the final revised rule. These matters—including the question of whether allowances allocated to substitution or compensating units under the January 11, 1993 rules should be returned to EPA in the future—were addressed when, as noted above, the final permits were issued with regard to these permit applications. The Agency considered, in the individual permit application proceedings, both the comments on this matter submitted in this rulemaking and those comments submitted on the draft permits.

V. Administrative Requirements

A. Docket

The docket is the organized and complete file of all the information considered by EPA in the development of this rulemaking. The Agency notes that, consistent with the May 4, 1994 settlement, several parties withdrew comments or portions of comments that they had submitted concerning matters addressed in the November 18, 1993 proposal. Along with the preamble of the proposal and final rule, the contents of the docket—except for interagency review materials and all comments or portions of comments that were withdrawn prior to the date of the Administrator's signature on this final rule—will constitute the record in case of judicial review. *See* 42 U.S.C. 7607(d)(7)(A).

B. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (Oct. 4, 1993), the Administrator must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a "significant regulatory action" because the rule seems to raise novel legal or policy issues. As such, this action was submitted to OMB for review. Any changes made in response to OMB suggestions or recommendations are documented in the public record. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** section of this preamble.

C. Paperwork Reduction Act

The information collection requirements in this rule have been approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, and have been assigned control number 2060–0258.

This collection of information has an estimated burden averaging from 8 to 16 hours per response for about 124 responses. These estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

An Information Collection Request document and estimates of the public reporting burden were prepared in connection with the January 11, 1993 regulations. 56 FR 63098; 58 FR 3650. The regulation modifications contained in today's proposal will not significantly change the reporting burden that was previously estimated.

Send comments regarding this burden analysis or any other aspect of this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, EPA, 401 M Street, S.W. (Mail Code 2136), Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, requires each federal agency to consider potential impacts of its regulations on small business "entities." Under 5 U.S.C. 604(a), an agency issuing a notice of proposed rulemaking must prepare and make available for public comment a regulatory flexibility analysis. Such an analysis is not required if the head of an agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, pursuant to 5 U.S.C. 605(b).

In the preamble of the January 11, 1993 regulations, the Administrator certified that those regulations, including the provisions revised by today's final rule, would not have a significant impact. 58 FR 3649. The final rule revisions adopted today are not significant enough to change the economic impact addressed in the preamble of the January 11, 1993 regulations, which were certified as not having a significant impact. The revisions will prevent the creation of about 200,000 excess, new allowances and thus will have an annual impact of about $318,000 per year in Phase I, i.e., 200,000 allowances times $159 (the weighted average winning bid for 1995 allowances in the EPA 1994 Allowance Auction on March 28, 1994. *See* 59 FR 19712, 19714 (Apr. 25, 1994)). Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the revised rule will not have a significant, adverse impact on a substantial number of small entities.

E. Miscellaneous

In accordance with section 117 of the Act, publication of this rule was preceded by consultation with any appropriate advisory committees, independent experts, and federal departments and agencies.

List of Subjects in 40 CFR Part 72

Environmental protection, Acid rain, Air pollution control, Electric utilities, Permits, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: November 14, 1994.

Carol M. Browner,

Administrator.

For the reasons set forth in the preamble, chapter I of title 40 of the Code of Federal Regulations is amended as follows.

PART 72—[AMENDED]

1. The authority citation for part 72 is revised to read as follows:

Authority: 42 U.S.C. 7601 and 7651, et seq.

2. Section 72.41 is amended by revising paragraphs (b)(1)(i), (c)(3) introductory text, (c)(3)(i)(B), (c)(3)(i)(C), (c)(3)(ii), (c)(4)(ii), (d)(2), and (e)(1)(i) and adding paragraphs (c)(3)(i)(D), (c)(3)(iii), and (d)(3) to read as follows:

§ 72.41 Phase I substitution plans.

* * * * *

(b)(1) * * *

(i) Each unit under paragraph (a)(2) of this section is under the control of the owner or operator of each unit under paragraph (a)(1) of this section that designates the unit under paragraph (a)(2) of this section as a substitution unit; and

* * * * *

(c) * * *

(3) Demonstration that the total emissions reductions achieved under the substitution plan will be equal to or greater than the total emissions reductions that would have been achieved without the plan, as follows:

(i) * * *

(B) Each of the following: the unit's 1985 actual SO_2 emissions rate; the unit's 1985 allowable SO_2 emissions rate; the unit's 1989 actual SO_2 emissions rate; the unit's 1990 actual SO_2 emissions rate; and, as of November 15, 1990, the most stringent unit-specific federally enforceable or State enforceable SO_2 emissions limitation covering the unit for 1995–1999. For purposes of determining the most stringent emissions limitation, applicable emissions limitations shall be converted to lbs/mmBtu in accordance with appendix B of this part. Where the most stringent emissions limitation is not the same for every year in 1995–1999, the most stringent emissions limitation shall be stated separately for each year.

(C) The lesser of: the unit's 1985 actual SO_2 emissions rate; the unit's 1985 allowable SO_2 emissions rate; the greater of the unit's 1989 or 1990 actual SO_2 emissions rate; or, as of November 15, 1990, the most stringent unit-specific federally enforceable or State enforceable SO_2 emissions limitation covering the unit for 1995–99. Where the most stringent emissions limitation is not the same for every year during 1995–1999, the lesser of the emissions rates shall be determined separately for each year using the most stringent emissions limitation for that year.

(D) The product of the baseline in paragraph (c)(3)(i)(A) of this section and the emissions rate in paragraph (c)(3)(i)(C) of this section, divided by 2000 lbs/ton. Where the most stringent emissions limitation is not the same for every year during 1995–1999, the product in the prior sentence shall be calculated separately for each year using the emissions rate determined for that year in paragraph (c)(3)(i)(C) of this section.

(ii)(A) The sum of the amounts in paragraph (c)(3)(i)(D) of this section for all substitution units to be governed by the plan. Except as provided in paragraph (c)(3)(ii)(B) of this section, this sum is the total number of allowances available each year under the substitution plan.

(B) Where the most stringent unit-specific federally enforceable or State enforceable SO_2 emissions limitation is not the same for every year during 1995–1999, the sum in paragraph (c)(3)(ii)(A) of this section shall be calculated separately for each year using the amounts calculated for that year in paragraph (c)(3)(i)(D) of this section. Each separate sum is the total number of allowances available for the respective year under the substitution plan.

(iii) Where, as of November 15, 1990, a non-unit-specific federally enforceable or State enforceable SO_2 emissions limitation covers the unit for any year during 1995–1999, the designated representative shall state each such limitation and propose a method for applying the unit-specific and non-unit-specific emissions limitations under paragraph (d) of this section.

(4) * * *

* * * * *

(ii) A list showing any annual distribution of the allowances in paragraph (c)(3)(ii) of this section from a substitution unit to a unit under paragraph (a)(1) of this section that, under the plan, designates the substitution unit.

* * * * *

(d) * * *

(2) In no event shall allowances be allocated to a substitution unit, under an approved substitution plan, for any year in excess of the sum calculated and applicable to that year under paragraph (c)(3)(ii) of this section, as adjusted by the Administrator in approving the plan.

(3) Where, as of November 15, 1990, a non-unit-specific federally enforceable or State enforceable SO_2 emissions limitation covers the unit for any year during 1995–1999, the Administrator will specify on a case-by-case basis a method for using unit-specific and non-unit-specific emissions limitations in allocating allowances to the substitution unit. The specified method will not treat a non-unit-specific emissions limitation as a unit-specific emissions limitation and will not result in substitution units retaining allowances allocated under paragraph (d)(1) of this section for emissions reductions necessary to meet a non-unit- specific emissions limitation. Such method may require an end-of-year review and the adjustment of the allowances allocated to the substitution unit and may require the designated representative of the substitution unit to surrender allowances by the allowance transfer deadline of the year that is subject to the review. Any surrendered allowances shall have the same or an earlier compliance use date as the allowances originally allocated for the year, and the designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, such allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

(e) * * *

(1) *Emissions Limitations.* (i) Each substitution unit governed by an approved substitution plan shall become a Phase I unit from January 1 of the year for which the plan takes effect until January 1 of the year for which the plan is no longer in effect or is terminated. The designated representative of a substitution unit shall surrender allowances, and the Administrator will deduct allowances, in accordance with paragraph (d)(3) of this section.

* * * * *

3. Section 72.43 is amended by revising paragraphs (a) introductory text, (a)(1) introductory text, (b)(1) introductory text, (b)(1)(ii)(A), (b)(3)(i), (c)(4)(i), (c)(4)(ii), (c)(4)(iv), (d), and (f)(1)(ii) and adding paragraph (a)(2) to read as follows:

§ 72.43 Phase I reduced utilization plans.

(a) Applicability. This section shall apply to the designated representative of:

(1) Any Phase I unit, including.

* * * * *

(2) Any affected unit that:

(i) Is not otherwise subject to any Acid Rain emissions limitation or emissions reduction requirements during Phase I; and

(ii) Meets the requirement, as set forth in paragraphs (c)(4)(ii) and (d) of this section, that for each year for which the unit is to be covered by the reduced utilization plan, the unit's baseline divided by 2,000 lbs/ton and multiplied by the lesser of the unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate does not exceed the sum of

(A) The lesser of 10 percent of the amount under paragraph (a)(2)(ii) of this section or 200 tons, plus

(B) The unit's baseline divided by 2,000 lbs/ton and multiplied by the lesser of: The greater of the unit's 1989 or 1990 actual SO_2 emissions rate; or, as of November 15, 1990, the most stringent federally enforceable or State enforceable SO_2 emissions limitation covering the unit for 1995–1999.

(b)(1) The designated representative of any unit under paragraph (a)(1) of this section shall include in the Acid Rain permit application for the unit a reduced utilization plan, meeting the requirements of this section, when the owners and operators of the unit plan to:

* * * * *

(ii) * * *

(A) Shifting generation of the unit to a unit under paragraph (a)(2) of this section or to a sulfur-free generator; or

* * * * *

(3)(i) Improved unit efficiency measures shall be implemented in the unit after December 31, 1987. Such measures include supply-side measures listed in appendix A, section 2.1 of part 73 of this chapter.

* * * * *

(c) * * *

(4) * * *

(i) Identification of each compensating unit or sulfur-free generator.

(ii) For each compensating unit.

(A) Each of the following: The unit's 1985 actual SO_2 emissions rate; the unit's 1985 allowable emissions rate; the unit's 1989 actual SO_2 emissions rate; the unit's 1990 actual SO_2 emissions rate; and, as of November 15, 1990, the most stringent unit-specific federally enforceable or State enforceable SO_2 emissions limitation covering the unit for 1995–1999. For purposes of determining the most stringent emissions limitation, applicable emissions limitations shall be converted to lbs/mmBtu in accordance with appendix B of this part. Where the most stringent emissions limitation is not the same for every year in 1995–1999, the most stringent emissions limitation shall be stated separately for each year.

(B) The unit's baseline divided by 2,000 lbs/ton and multiplied by the lesser of the unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate.

(C) The unit's baseline divided by 2000 lbs/ton and multiplied by the lesser of: The greater of the unit's 1989 or 1990 actual SO_2 emissions rate; or, as of November 15, 1990, the most stringent unit-specific federally enforceable or State enforceable SO_2 emissions limitation covering the unit for 1995–1999. Where the most stringent emissions limitation is not the same for every year in 1995–1999, the calculation in the prior sentence shall be made separately for each year.

(D) The difference between the amount under paragraph (c)(4)(ii)(B) of this section and the amount under paragraph (c)(4)(ii)(C) of this section. If the difference calculated in the prior sentence for any year exceeds the lesser of 10 percent of the amount under paragraph (c)(4)(ii)(B) of this section or 200 tons, the unit shall not be designated as a compensating unit for the year. Where the most stringent unit-specific federally enforceable or State enforceable SO_2 emissions limitation is not the same for every year in 1995–1999, the difference shall be calculated separately for each year.

(E) The allowance allocation calculated as the amount under paragraph (c)(4)(ii)(B) of this section. If the compensating unit is a new unit, it shall be deemed to have a baseline of zero and shall be allocated no allowances.

(F) Where, as of November 15, 1990, a non-unit-specific federally enforceable or State enforceable SO_2 emissions limitation covers the unit for any year in 1995–1999, the designated representative shall state each such limitation and propose a method for applying unit-specific and non-unit-specific emissions limitations under paragraph (d) of this section.

* * * * *

(iv) For each compensating unit or sulfur-free generator not in the dispatch system of the unit reducing utilization under the plan, the system directives or power purchase agreements or other contractual agreements governing the acquisition, by the dispatch system, of the electrical energy that is generated by the compensating unit or sulfur-free generator and on which the plan relies to accomplish reduced utilization. Such contractual agreements shall identify the specific compensating unit or sulfur-free generator from which the dispatch system acquires such electrical energy.

* * * * *

(d) *Administrator's Action.* (1) If the Administrator approves the reduced utilization plan, he or she will allocate allowances, as provided in the approved plan, to the Allowance Tracking System account for any designated compensating unit upon issuance of an Acid Rain permit containing the plan, except that, if the plan is conditionally approved, the allowances will be allocated upon revision of the permit to activate the plan.

(2) Where, as of November 15, 1990, a non-unit-specific federally enforceable or State enforceable emissions limitation covers the unit for any year during 1995–1999, the Administrator will specify on a case-by-case basis a method for using unit-specific and non-unit specific emissions limitations in approving or disapproving the compensating unit. The specified method will not treat a non-unit-specific emissions limitation as a unit-specific emissions limitation and will not result in compensating units retaining allowances allocated under paragraph (d)(1) of this section for emissions reductions necessary to meet a non-unit-specific emissions limitation. Such method may require an end-of-year review and the disapproval and de-designation, and adjustment of the allowances allocated to, the compensating unit and may require the designated representative of the compensating unit to surrender allowances by the allowance transfer deadline of the year that is subject to the review. Any surrendered allowances shall have the same or an earlier compliance use date as the allowances originally allocated for the year, and the designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, such allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

* * * * *

(f) * * *

(1) * * *

(ii) The designated representative of any Phase I unit (including a unit governed by a reduced utilization plan relying on energy conservation, improved unit efficiency, sulfur-free generation, or a compensating unit) shall surrender allowances, and the Administrator will deduct or return allowances, in accordance with paragraph (d)(2) of this section and subpart I of this part.

* * * * *

4. Section 72.91 is amended by revising paragraphs (a)(3)(iii) introductory text (formula is unchanged), (a)(3)(iv), (a)(4), (a)(5), (a)(6), and (b)(2) and adding paragraph (a)(7) to read as follows:

§ 72.91 Phase I unit adjusted utilization.

(a) * * *

(3) * * *

(iii) "Shifts to designated sulfur-free generators" is the reduction in utilization (in mmBtu), for the calendar year, that is accounted for by all sulfur-free generators designated under the reduced utilization plan in effect for the calendar year. This term equals the sum, for all such generators, of the "shift to sulfur-free generator." "Shift to sulfur-free generator" shall equal the amount, to the extent documented under paragraph (a)(6) of this section, calculated for each generator using the following formula:

* * * * *

(iv) "Shifts to designated compensating units" is the reduction in utilization (in mmBtu) for the calendar year that is accounted for by increased generation at compensating units designated under the reduced utilization plan in effect for the calendar year. This term equals the heat rate, under paragraph (a)(3) of this section, of the unit reducing utilization multiplied by the sum, for all such compensating units, of the "shift to compensating unit" for each compensating unit. "Shift to compensating unit" shall equal the amount of compensating generation (in Kwh), to the extent documented under paragraph (a)(6) of this section, that the designated representatives of the unit reducing utilization and the compensating unit have certified (in their respective annual compliance certification reports) as the amount that will be converted to mmBtus and used, in accordance with paragraph (a)(4) of this section, in calculating the adjusted utilization for the compensating unit.

(4) "Compensating generation provided to other units" is the total amount of utilization (in mmBtu) necessary to provide the generation (if any) that was shifted to the unit as a designated compensating unit under any other reduced utilization plans that were in effect for the unit and for the calendar year. This term equals the heat rate, under paragraph (a)(3) of this section, of such unit multiplied by the sum of each "shift to compensating unit" that is attributed to the unit in the annual compliance certification reports submitted by the Phase I units under such other plans and that is certified under paragraph (a)(3)(iv) of this section.

(5) Notwithstanding paragraphs (a)(3) (i), (ii), and (iii) of this section, where two or more Phase I units include in "plan reductions", in their annual compliance certification reports for the calendar year, expected kilowatt hour savings or reduction in heat rate from the same specific conservation or improved unit efficiency measures or increased utilization of the same sulfur-free generator:

(i) The designated representatives of all such units shall submit with their annual reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings, reduction in heat rate, or increased utilization among such units.

(ii) Each designated representative shall include in the annual report only the respective unit's share of the total kilowatt hour savings, reduction in heat rate, or increased utilization, in accordance with the certification under paragraph (a)(5)(i) of this section.

(6)(i) Where a unit includes in "plan reductions" under paragraph (a)(3) of this section the increase in utilization of any sulfur-free generator, the designated representative of the unit shall submit, with the annual compliance certification report, documentation demonstrating that an amount of electrical energy at least equal to the "shift to sulfur-free generator" attributed to the sulfur-free generator in the annual report was actually acquired by the unit's dispatch system from the sulfur-free generator.

(ii) Where a unit includes in "plan reductions" under paragraph (a)(3) of this section utilization of any compensating unit, the designated representative of the unit shall submit with the annual compliance certification report, documentation demonstrating that an amount of electrical energy at least equal to the "shift to compensating unit" attributed to the compensating unit in the annual report was actually acquired by the unit's dispatch system from the compensating unit.

(7) Notwithstanding paragraphs (a)(3)(i), (ii), (iii), and (iv), (a)(4), and (a)(5) of this section, "plan reductions" minus "compensating generation provided to other units" shall not exceed "baseline" minus "actual utilization."

(b) * * *

(2) Notwithstanding paragraph (b)(1)(i) of this section, where two or more Phase I units include in the confirmation report the verified kilowatt hour savings or reduction in heat rate from the same specific conservation or improved unit efficiency measures:

(i) The designated representatives of all such units shall submit with their confirmation reports a certification signed by all such designated representatives. The certification shall apportion the total kilowatt hour savings or reduction in heat rate among such units.

(ii) Each designated representative shall include in the confirmation report only the respective unit's share of the total savings or reduction in heat rate in accordance with the certification under paragraph (b)(2)(i) of this section.

* * * * *

[FR Doc. 94-28708 Filed 11-21-94; 8:45 am]

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November 22, 1994

Part V

Environmental Protection Agency

40 CFR Part 72

Acid Rain Program: Permits; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 72

[FRL–5109–6]

RIN 2060–AF55

Acid Rain Program: Permits

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: Title IV of the Clean Air Act, as amended by Public Law 101–549, the Clean Air Act Amendments of 1990 (the Act), authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. On January 11, 1993, the Agency promulgated final rules under title IV. Several parties filed petitions for review of the rules. On August 10, 1994, EPA and other parties signed a settlement agreement addressing certain substitution plan issues.

Based on a review of the record, the Agency concludes that the January 11, 1993 regulations concerning the eligibility of units to be designated as substitution units should be revised. Under sections 404(b) and (c) of the Act, a unit that is not listed in Table A of section 404 as being subject to Phase I of the Acid Rain Program (i.e., a non-Table A unit) and that is under the control of the owner or operator of a unit listed in Table A of section 404 (i.e., a Table A unit) may be designated as a substitution unit. The January 11, 1993 regulations state that the Table A unit and each non-Table A unit that the Table A unit designates as a substitution unit must have "the same owner or operator." The Agency is revising the regulations in order to specify more clearly the circumstances under which the statutory "control" requirement for substitution plans is met. The rule revision is being issued as a direct final rule because it is consistent with the August 10, 1994 settlement and no adverse comment is expected.

EFFECTIVE DATE: This direct final rule will be effective on January 3, 1995 unless significant, adverse comments are received by December 22, 1994. If significant, adverse comments are timely received on any provision of the direct final rule, that provision of the direct final rule will be withdrawn through a document in the **Federal Register.**

ADDRESSES: Docket No. A–93–40, containing supporting information used to develop the proposal, copies of all comments received, and responses to comments, is available for public inspection and copying from 8:30 a.m. to 12 p.m. and 1 p.m. to 3:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section (LE–131), Waterside Mall, room 1500, 1st floor, 401 M Street, SW., Washington DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Dwight C. Alpern, Attorney-advisor, at (202) 233–9151, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460, or the Acid Rain Hotline at (202) 233–9620.

SUPPLEMENTARY INFORMATION: All public comment received on any provision of this direct final rule on which significant, adverse comments are timely received will be addressed in a subsequent final rule based on the relevant portions of the rule revision that is noticed as a proposed rule in the **Proposed Rules Section of this Federal** Register and that is identical to this direct final rule.

The contents of the preamble to the final rule are as follows:

I. Control Requirement for Designating Substitution Units

Sections 404(b) and (c) of the Act set forth the requirements for submission and approval of substitution plans, under which a unit listed on Table A of section 404 designates one or more non-Table A units as substitution units and brings them into Phase I of the Acid Rain Program. Congress established substitution plans as a compliance option to increase units' compliance flexibility and reduce their overall costs of compliance in Phase I while still achieving the emissions reductions intended by Congress under title IV. See 58 FR 60950–60951 (Nov. 18, 1993).

A substitution plan allows the owner or operator of a Table A unit to reassign the unit's emissions reduction obligations to a designated non-Table A unit "under the control of" that owner or operator. 42 U.S.C. 7651c(b). Upon approval of the reassignment, the non-Table A unit becomes subject to all requirements for Phase I units with regard to sulfur dioxide and is allocated allowances. Emissions reductions by the non-Table A unit may therefore free up allowances, which may be used by the Table A unit (or any other unit) in lieu of making emissions reductions.

Section 71.41 of the January 11, 1993 regulations provided that the statutory requirement of control by the Table A unit's owner or operator over the non-Table A unit is satisfied where such units have "the same owner or operator." 40 CFR 72.41(b)(1)(i) (1993). The regulation also provided that having the same designated representative would be treated as having the same operator and would thus meet the control requirement. *Id.*; see also 58 FR 3600. On March 12, 1993, petitions for review of the January 11, 1993 regulations were filed with the U.S. Court of Appeals for the District of Columbia Circuit. Several petitioners challenged the provisions implementing the control requirement.

On November 18, 1993, the Agency issued proposed revisions to the January 11, 1993 regulations, including the provisions concerning the control requirement. The Agency proposed to reverse its interpretation that having a common designated representative alone meets the statutory control requirement for substitution plans and to revise the regulations accordingly. 58 FR 60957–60958. Several commenters addressed the control requirement in their comments on the November 18, 1993 proposal. Some commenters opposed any change in the January 11, 1993 provisions concerning the control requirement.

Other commenters noted that, although § 72.41(b)(1)(i) requires that the substitution and Table A units have "the same owner or operator" (40 CFR 72.41(b)(1)(i) (1993)), section 404(b) of the Act requires that the substitution unit be under the control of the Table A unit owner or operator. They argued that, in implementing section 404(b) and (c), the Agency should also focus on whether there is such control. They suggested that common ownership of the units is not necessarily determinative of whether the control requirement is met. They alleged that where the units have multiple owners only one of which is in common, the control requirement may not be met, e.g., where the common owner owns only a very small percentage of the proposed substitution unit. On the other hand, where the units lack any common owner or operator, the control requirement allegedly may be met through contractual arrangements under which the owner and operator of the substitution unit commit, *inter alia*, to make emissions reductions and deliver allowances to the owner and operator of the Phase I unit.

In a separate final rule in this **Federal Register**, the Agency adopted the reasoning, set forth in the November 18, 1993 preamble (58 FR 60957–60958) and in the preamble of the Acid Rain regulations on nitrogen oxides (59 FR 13554–13555 (Mar. 22, 1994)), that a designated representative is not, merely by holding that position, also an operator. In that separate final rule, the Agency revised the January 11, 1993 regulations to use the statutory language requiring control by the Table A unit owner or operator and to provide that having a common designated representative does not alone meet the control requirement for substitution units. However, the Agency did not address in that separate document comments raising issues concerning: under what circumstances the existence of one or more common owners satisfies the control requirement; and whether and, if so, under what circumstances control can be established by contract if there are no common owners or common operators. The Agency addresses below those issues and the comments on those issues.

II. Modifications of the January 11, 1993 Regulation Concerning the Control Requirement for Substitution Units

A. Control by Common Owner or Operator

Section 404(b) of the Act allows that the "owner or operator" of a Table A unit to designate, as a substitution unit, a non-Table A unit "under the control of such owner or operator." 42 U.S.C. 7651c(b). The Agency agrees with commenters that, like section 404(b), the regulation implementing that section should focus on whether such control exists.

Because many units have multiple owners with varying percentages of ownership, there is a wide range of possible relationships between a Table A unit and a non-Table A unit, ranging, for example, from no common ownership to 100% common ownership and including all the possible variations in between. In order to avoid burdensome case-by-case determinations of whether each particular set of facts meets the control requirement and in order to provide more certainty for utilities and the public concerning what units qualify for inclusion in substitution plans, the Agency is establishing generic criteria for applying the control requirement. Further, the generic criteria are based on the potential ability of owners and operators to exercise control, not the actual exercise of such control potential. Determining what entities actually make decisions governing the operation of a unit could require the Agency to make lengthy case-by-case inquiries into the details of utility operations and involve the Agency in matters beyond its expertise.

In taking this approach, the Agency maintains that section 404(b) should be interpreted to require that owners or operators of a Table A unit have the ability to exercise a significant degree of control over a non-Table A unit. The simplest case for applying this requirement is where the Table A and non-Table A units have only a single owner or where, regardless of their ownership, the units have a common operator. Under these circumstances, it seems clear that the single owner or the operator of the Table A unit has the ability to control the non-Table A unit.

For units with multiple owners, the application of the control requirement becomes somewhat more complex if they do not have a common operator. If one or more owners and operators of a Table A unit own an aggregate share of 50% or more of the capacity of a non-Table A unit, no major decisions concerning the unit can be made without the concurrence of such Table A unit owners and operators. The Agency maintains, therefore, that they can control the non-Table A unit to a significant extent and meet the control requirement.

Even where the aggregate ownership share of the one or more owners and operators of a Table A unit in a non-Table A unit is less than 50%, the degree of control may still be significant. Such control is evidenced by the ability of such non-Table A unit owners to determine the dispatch of their respective shares of electricity generated by the non-Table A unit. Decisions by such owners whether or not to take their shares of generation can significantly affect the overall operation of the unit. While the Agency recognizes that adopting a minimum level of ownership in the non-Table A unit for meeting the control requirement is necessarily somewhat arbitrary, the Agency maintains that, as a matter of logic, there is some level of ownership below which the owners lack significant control. Further, establishing such a minimum level of ownership discourages gaming through the acquisition of minute ownership shares simply to enable the new owner to qualify the non-Table A unit as a substitution unit.

The Agency believes that an aggregate ownership interest of 10% or more, and less than 50%, of the capacity of the non-Table A unit meets the control requirement, provided that such owners have the ability to determine how their respective shares of the non-Table A unit's generation are dispatched. The Agency notes that, in some regions of the country, utilities have entered into power pool agreements under which the utilities agree to centralize in the power pool the dispatch of their units. Power pools with central economic dispatch enable member utilities to minimize operating costs through the use of the units in the pool that have the lowest generation costs. In light of the important benefits of such power pools, the Agency maintains that utilities in power pools should not be disadvantaged under section 404(b). Consequently, the determination of whether owners of a non-Table A unit have, by right of contract, the ability to dispatch their respective shares of the unit's generation should be made without regard to whether owners that had contractual dispatch authority have surrendered that authority to a power pool.

In sum, the Agency is establishing generic criteria for determining whether the control requirement under section 404(b) is met. The first category that meets this requirement is where one or more owners or operators of a Table A unit have an aggregate ownership interest of 50% or more in the non-Table A unit or where the two units have a common operator.[1] The second category that meets the control requirement is where: a Table A and non-Table A unit lack a common operator; one or more owners or operators of a Table A unit have an aggregate ownership interest of 10% or more and less than 50% in the non-Table A unit; and such owners or operators have the contractual ability to determine the dispatch of their respective shares of the non-Table A unit's generation. The final regulation requires the designated representatives submitting substitution plans to state in the submission what category is applicable to the units in the plan and to provide, upon request, documentation supporting such statements. These statements, like all information included in submissions by the designated representative, are covered by the certification required under § 72.21(b) concerning the truth,

[1] In summing the ownership shares of individual Table A unit owners and operators in the capacity of a non-Table unit, a given share, and the generation associated with such share, obviously cannot be double-counted. Otherwise, the sum of the ownership shares of all persons owning a non-Table A unit could exceed 100%.

accuracy, and completeness of the statements.

B. Control by Contract

The Agency agrees that, under certain circumstances, control over a substitution unit by the owners and operators of the Table A unit may be established by contract where the above-described criteria based on a common operator or the level of common ownership are not met. The contract must be a binding agreement between the owners and operators of a Table A unit and the owners and operators of the non-Table A unit that is designated as the Table A unit's substitution unit. Several commenters supported an interpretation of section 404(b) that would allow the control requirement to be met through a contract. The final regulation specifies the circumstances under which the Administator will find that control is established by contract.

Several determinations have guided the Agency's development of the regulation concerning control by contract. First, the Agency believes that the regulation should set forth detailed, generic requirements for establishing control by contract. Leaving the specification of detailed requirements to case-by-case development would increase the burden both on the owners and operators interested in submitting contract-based substitution plans and on the Agency, which must review such submissions. A commenter supporting the approval of contract-based substitution plans suggested that the Agency develop generic criteria.

Second, the Agency believes that the control requirement of section 404(b) of the Act should be interpreted in light of the emissions reduction goals of title IV. The Agency maintains that a determination of whether control is established by contract should focus on whether the owners and operators of the Table A unit have the ability, under the contract, to require emissions reductions by the non-Table A unit and thereby to affect the overall operation of the unit. It is not necessary in this context for the Table A unit's owners and operators to have contractual authority over all facets of the non-Table A unit's day-to-day operations.

Third, if the control requirement is to be met by simply showing that Table A unit owners and operators have the ability, by contract, to require emissions reductions by the non-Table A unit, the Agency maintains that the contract must require emissions reductions that are significant, new reductions that would not otherwise have been implemented by the non-Table A unit. It is difficult to see how control could be demonstrated if a contract with a Table A unit merely required a non-Table A unit to "make" reductions that the non-Table A unit had already implemented, was already in the process of implementing, or would have implemented even in the absence of the contract. Further, because a unit might be able to realize relatively minor reductions while making little change in its operations, the scale of the reductions required by contract should be significant in order to demonstrate control of the non-Table A unit by owners and operators that otherwise lack any operational responsibilities for that unit. A commenter suggested that the contract between the Table A and non-Table A units should specify a percentage emissions rate reduction that the non-Table A unit is required to achieve.

To ensure that the contract requires significant, new reductions by the non-Table A unit, the final regulation requires that the contract establish a maximum annual average SO_2 emissions rate for the unit. The maximum emissions rate must be less than or equal to 70% of the lesser of the following emissions rates for the non-Table A unit: the 1985 actual SO_2 emissions rate; the 1985 allowable SO_2 emissions rate; the greater of the 1989 or 1990 actual SO2 emissions rate; the most stringent federally enforceable or State enforceable SO_2 emissions limitation, as of November 15, 1990, applicable in Phase I; and the lesser of the average actual SO_2 emissions rate or the most stringent federally enforceable or State enforceable SO_2 emissions limitation for the four-quarter period immediately preceding the submission of the contract-based substitution plan. [2] The latter set of emissions rates (i.e., the current actual and allowable rates) are included to ensure that the required reduction in the unit's emissions rate is at least 30% of the emissions rate achieved, or required to be achieved, by the non-Table A unit around the time of the submission of the substitution plan. The other emissions rates (i.e., those for 1985, 1989, 1990, and Phase I) are used to ensure that the current actual or allowable rate does not represent a spike in the emissions rate achieved by or required for the unit since 1985. [3] A commenter supported using all of these emissions rates to set a maximum emissions rate for the non-Table A unit.

The Agency maintains that a 30% reduction in the emissions rate that the non-Table A unit would otherwise achieve represents a significant reduction. A commenter supporting approval of contract-based substitution plans asserted that it has identified about 30 Phase II units that lack a common owner or operator with a Table A unit and for which such plans would be economically feasible. The commenter stated that this group of units could reduce their current emissions rates by 50 to 70% and indicated that a 30% reduction might be an acceptable requirement for approval of this type of substitution plan.

As a further means of ensuring that the non-Table A unit's reductions are new, the final regulation requires that the contract-based substitution plan include a description of the actions that will be undertaken so that the non-Table A unit will comply with the maximum emissions rate. Such actions may include, for example, the addition or modification of a scrubber or fuel switching. The owners and operators of the Table A and non-Table A units must show that the described actions will not be implemented in Phase I unless the non-Table A unit is approved as a substitution unit. The description of the actions that will be taken must be sufficiently detailed so that the Agency can determine whether the showing has been made. Information relevant to the showing includes, *inter alia*, whether contracts implementing these actions were entered into before submission of the substitution plan. Under the regulation, the owners and operators must implement the described actions but may seek to amend the substitution plan to change the required actions.

In general, the Agency maintains that it is difficult to make determinations, particularly in a large number of cases, of whether owners and operators will take certain future actions in the absence of a substitution plan. However, the Agency must make a determination of this type in reviewing the actions described in each contract-based substitution plan in order to make sure that the non-Table A unit is really obligated to make new reductions. This

[2] Some units are subject to a non-unit-specific emissions limit (e.g., a utility-wide emissions tonnage or rate limit). The final regulation provides that if such a unit is designated as a substitution unit in a contract-based substitution plan, the Administrator will determine on a case-by-case basis how to apply the non-unit-specific limit in setting the maximum annual SO_2 emissions rate. If a non-unit-specific Federal limit was in effect and applicable to the unit in 1985, that limit is already reflected in the 1985 allowable SO_2 emissions rate (in the National Allowance Data Base), which will be treated as representing the non-unit- specific Federal limit.

[3] For the reasons set forth in a separate final rule in this **Federal Register**, these other emissions rates are also used to allocate allowances for any substitution unit and to ensure that allowances are not allocated for emissions reductions that would have been made without a substitution plan.

will be a one-time determination made when the plan is approved (or disapproved) unless the designated representative subsequently seeks to modify the description of actions in the plan. Further, the Agency does not expect a large number of contract-based substitution plans to be submitted. As noted above, commenters have identified only about 30 units for which such a plan would be economic.

Fourth, it is important to ensure that the contract imposes an effective emissions reduction requirement—i.e., a requirement that is likely to be enforced by Table A unit owners and operators claiming control of the non-Table A unit. Consequently, the contract should include a meaningful remedy in the event that the required emissions reductions are not achieved. The concept of requiring a meaningful remedy in the event of default was supported by a commenter.

If the Table A unit owners and operators must surrender allowances to the Administrator to the extent that the non-Table A unit fails to make the required emissions reductions, then the Table A owners and operators will bear responsibility for the reductions that they claim to control and will have the incentive to take actions to ensure achievement of the reductions. This puts the Table A owners and operators in a position similar to that of owners and operators that control a unit directly by owning or operating the unit. If, instead of such allowance surrender by the Table A unit, the non-Table A unit had to give allowances to the Table A unit (or to the Agency), then the Table A unit owners and operators would bear no responsibility for the non-Table A unit that they claim to control. Further, without elaborate limitations on the transfer of allowances between the Table A and non-Table A units, there would be no way of preventing the units from arranging a future return to the non-Table A unit of any allowances surrendered by the non-Table A unit to the Table A unit.

Under the final regulation, if the non-Table A unit fails to comply with the maximum emissions rate during the year, the Table A unit owners and operators must surrender a number of allowances equal to the non-Table A unit's baseline multiplied by the difference between the actual emissions rate for the year and the maximum emissions rate. This approach segregates out the effect of utilization changes and leaves such changes to be handled under the reduced utilization and allowance surrender provisions (e.g., §§ 72.43, 72.91, and 72.92) applicable to all Phase I units. The surrendered allowances must have the same or an earlier compliance use date as the allowances allocated to the non-Table A unit for the year, and the surrender must be made on or before the allowance transfer deadline. In order to encourage early reductions at non-Table A units and innovative approaches to achieving such reductions, the surrender and deduction of allowances will be the only remedy under the Act for failure to meet the maximum emissions rate. Of course, the deduction of allowances for failure to achieve the maximum emissions rate may result in a unit having insufficient allowances to cover its annual emissions, and the full panoply of remedies for excess emissions will then apply.

Finally, in order to facilitate the Table A unit owners' and operators' exercise of control and the Agency's review and enforcement, where necessary, of the substitution plan, the units involved should have a common designated representative. A commenter supported the need for a common designated representative for this type of substitution plan.[4] The final regulation provides that the requirement to have a common designated representative is not met by simply having a common alternate designated representative. This is because, as explained in the preamble of the November 18, 1993 proposed rule, an alternate designated representative does not carry the same level of responsibilities as, and thus is not equivalent to, a designated representative. 58 FR 60958.

C. Plan Termination if Control Requirement is no Longer met

The January 11, 1993 regulations provide that where, as a result of ownership or other changes, the units in a substitution plan no longer meet the common owner or operator requirement in those regulations, the substitution plan must be terminated. The final regulation adopted here takes a similar approach. If there are changes that result in the control requirement no longer being met, the designated representative must terminate the plan, whether the plan is based on common owners or operators or on a contract. The Administrator may, on his or her own motion, terminate the plan under such circumstances.

[4] The commenter also suggested that the non-Table A owners and operators be required to submit quarterly and annual reports to the Table A unit owners and operators and to indemnify such owners and operators for any violations at the non-Table A unit. These requirements are not in the final rule because the Agency believes that these matters are not central to the issue of control and are better left to the owners and operators of the two units.

The only exception to this requirement is for substitution plans approved, and included in final permits issued, under the January 11, 1993 regulations and the Partial Settlement in *Environmental Defense Fund* v. *Carol M. Browner*, No. 93–1203 (D.C. Cir. 1993) (signed May 4, 1994). So long as the Table A and non-Table A units under each plan continue to meet the common owner, operator, or designated representative requirement in the January 11, 1993 regulations, such plans will not be terminated for the first year (and, in some cases, for the second year) for which the substitution unit received a total number of allowances equal to the number provided in those regulations. This exception is consistent with both the May 4, 1993 settlement and the Second Partial Settlement in *Environmental Defense Fund* v. *Carol M. Browner*, No. 93–1203 (D.C. Cir. 1993) (signed August 10, 1994). The Agency maintains that both settlements reasonably resolve the substitution plan issues raised in the litigation, including the issues relating to the control requirement.

III. Administrative Requirements

A. Docket

The docket is the organized and complete file of all the information considered by EPA in the development of this rulemaking. Along with the preamble of the direct final rule, the contents of the docket—except for interagency review materials—will constitute the record in case of judicial review. See 42 U.S.C. 7607(d)(7)(A).

B. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (Oct. 4, 1993), the Administrator must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a "significant regulatory action" because the rule seems to raise novel legal or policy issues. As such, this action was submitted to OMB for review. Any changes made in response to OMB suggestions or recommendations are documented in the public record. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the ADDRESSES section of this preamble.

C. Paperwork Reduction Act

The information collection requirements in this rule have been approved by OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, and have been assigned control number 2060–0258.

This collection of information has an estimated burden averaging 17.5 to 28 hours per response for about 43 responses. These estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

An Information Collection Request document and estimates of the public reporting burden were prepared in connection with the January 11, 1993 regulations. 56 FR 63098; 58 FR 3650. The regulation modifications contained in this document will not significantly change the reporting burden that was previously estimated.

Send comments regarding this burden analysis or any other aspect of this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, EPA, 401 M Street, SW., (Mail Code 2136), Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503, marked "Attention: Desk Officer for EPA."

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, requires each Federal agency to consider potential impacts of its regulations on small business "entities." Under 5 U.S.C. 604(a), an agency issuing a notice of proposed rulemaking must prepare and make available for public comment a regulatory flexibility analysis. Such an analysis is not required if the head of an agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, pursuant to 5 U.S.C. 605(b).

In the preamble of the January 11, 1993 regulations, the Administrator certified that those regulations, including the provisions revised by today's final rule, would not have a significant impact. 58 FR 3649. The final rule revisions adopted today are not significant enough to change the economic impact addressed in the preamble of the January 11, 1993 regulations, which were certified as not having a significant impact. Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the revised rule will not have a significant, adverse impact on a substantial number of small entities.

E. Miscellaneous

In accordance with section 117 of the Act, publication of this rule was preceded by consultation with any appropriate advisory committees, independent experts, and Federal departments and agencies.

List of Subjects in 40 CFR Part 72

Environmental protection, Acid rain, Air pollution control, Electric utilities, Permits, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: November 14, 1994.

Carol M. Browner,

Administrator.

For the reasons set forth in the preamble, chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 72—[AMENDED]

1. The authority citation for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651 *et seq.*

2. Section 72.41 is amended by revising paragraphs (c)(5) and (e)(3)(iv) and adding paragraphs (c)(6), (c)(7), and (e)(1)(iii) to read as follows:

§ 72.41 Phase I substitution plans.

* * * * *

(c) * * *

(5) A demonstration that the substitution plan meets the requirement that each unit under paragraph (a)(2) of this section is under the control of the owner or operator of each unit under paragraph (a)(1) of this section that designates the unit under paragraph (a)(2) of this section as a substitution unit. The demonstration shall be one of the following:

(i) If the unit under paragraph (a)(1) of this section has one or more owners or operators that have an aggregate percentage ownership interest of 50 percent or more in the capacity of the unit under paragraph (a)(2) of this section or the units have a common operator, a statement identifying such owners or operators and their aggregate percentage ownership interest in the capacity of the unit under paragraph (a)(2) of this section or identifying the units' common operator. The designated representative shall submit supporting documentation upon request by the Administrator.

(ii) If the unit under paragraph (a)(1) of this section has one or more owners or operators that have an aggregate percentage ownership interest of at least 10 percent and less than 50 percent in the capacity of the unit under paragraph (a)(2) of this section and the units do not have a common operator, a statement identifying such owners or operators and their aggregate percentage ownership interest in the capacity of the unit under paragraph (a)(2) of this seciton and stating that each such owner or operator has the contractual right to direct the dispatch of the electricity that, because of its ownership interest, it has the right to receive from the unit under paragraph (a)(2) of this section. The fact that the electricity that such owner or operator has the right to receive is centrally dispatched through a power pool will not be the basis for determining that the owner or operator does not have the contractual right to direct the dispatch of such electricity. The designated representative shall submit supporting documentation upon request by the Administrator.

(iii) A copy of an agreement that is binding on the owners and operators of the unit under paragraph (a)(2) of this section and the owners and operators of the unit under paragraph (a)(1) of this section, provides each of the following elements, and is supported by documentation meeting the requirements of paragraph (c)(6) of this section:

(A) The owners and operators of the unit under paragraph (a)(2) of this section must not allow the unit to emit sulfur dioxide in excess of a maximum annual average SO_2 emissions rate (in lbs/mmBtu), specified in the agreement, for each year during the period that the substitution plan is in effect.

(B) The maximum annual average SO_2 emissions rate for the unit under paragraph (a)(2) of this section shall not exceed 70 percent of the lesser of: the unit's 1985 actual SO_2 emissions rate; the unit's 1985 allowable SO_2 emissions rate; the greater of the unit's 1989 or 1990 actual SO_2 emissions rate; the most stringent federally enforceable or State enforceable SO_2 emissions limitation, as of November 15, 1990, applicable to the unit in Phase I; or the lesser of the average actual SO_2 emissions rate or the most stringent federally enforceable or State enforceable SO_2 emissions limitation for the unit for four consecutive quarters that immediately precede the 30-day period ending on the date the substitution plan is submitted to the Administrator. If the unit is covered by a non-unit-specific federally enforceable or State enforceable SO_2 emissions limitation in the four consecutive quarters or, as of November 15, 1990, in Phase I, the Administrator will determine, on a case-by-case basis, how to apply the non-unit-specific emissions limitation for purposes of determining whether the maximum annual average SO_2 emissions rate meets the requirement of the prior sentence. If a non-unit-specific federally enforceable SO_2 emissions limitation is not different from a non-unit-specific federally enforceable SO_2 emissions limitation that was effective and applicable to the unit in 1985, the Administrator will apply the non-unit-specific SO_2 emissions limitation by using the 1985 allowable SO_2 emissions rate.

(C) For each year that the actual SO_2 emissions rate of the unit under paragraph (a)(2) of this section exceeds the maximum annual average SO_2 emissions rate, the designated representative of the unit under paragraph (a)(1) of this section must surrender allowances for deduction from the Allowance Tracking System account of the unit under paragraph (a)(1) of this section. The designated representative shall surrender allowances authorizing emissions equal to the baseline of the unit under paragraph (a)(2) of this section multiplied by the difference between the actual SO_2 emissions rate of the unit under paragraph (a)(2) of this section and the maximum annual average SO_2 emissions rate and divided by 2000 lbs/ton. The surrender shall be made by the allowance transfer deadline of the year of the exceedance, and the surrendered allowances shall have the same or an earlier compliance use date as the allowances allocated to the unit under paragraph (a)(2) of this section for that year. The designated representative may identify the serial numbers of the allowances to be deducted. In the absence of such identification, allowances will be deducted on a first-in, first-out basis under § 73.35(c)(2) of this chapter.

(D) The unit under paragraph (a)(2) of this section and the unit under paragraph (a)(1) of this section shall designate a common designated representative during the period that the substitution plan is in effect. Having a common alternate designated representative shall not satisfy the requirement in the prior sentence.

(E) Except as provided in paragraph (c)(6)(i) of this section, the actual SO_2 emissions rate for any year and the average actual SO_2 emissions rate for any period shall be determined in accordance with part 75 of this chapter.

(6) A demonstration under paragraph (c)(5)(iii) of this section shall include the following supporting documentation:

(i) The calculation of the average actual SO_2 emissions rate and the most stringent federally enforceable or State enforceable SO_2 emissions limitation for the unit for the four consecutive quarters that immediately preceded the 30-day period ending on the date the substitution plan is submitted to the Administrator. To the extent that the four consecutive quarters include a quarter prior to January 1, 1995, the SO_2 emissions rate for the quarter shall be determined applying the methodology for calculating SO_2 emissions set forth in appendix C of this part. This methodology shall be applied using data submitted for the quarter to the Secretary of Energy on United States Department of Energy Form 767 or, if such data has not been submitted for the quarter, using the dataprepared for such submission for the quarter.

(ii) A description of the actions that will be taken in order for the unit under paragraph (a)(2) of this section to comply with the maximum annual average SO_2 emissions rate under paragraph (c)(5)(iii) of this section.

(iii) A description of any contract for implementing the actions described in paragraph (c)(6)(ii) of this section that was executed before the date on which the agreement under paragraph (c)(5)(iii) of this section is executed. The designated representative shall state the execution date of each such contract and state whether the contract is expressly contingent on the agreement under paragraph (c)(5)(iii) of this section.

(iv) A showing that the actions described under paragraph (c)(6)(ii) of this section will not be implemented during Phase I unless the unit is approved as a substitution unit.

(7) The special provisions in paragraph (e) of this section.

* * * * *

(e) * * *

(1) * * *

(iii) Where an approved substitution plan includes a demonstration under paragraphs (c)(5)(iii) and (c)(6) of this section.

(A) The owners and operators of the substitution unit covered by the demonstration shall implement the actions described under paragraph (c)(6)(ii) of this section, as adjusted by the Administrator in approving the plan or in revising the permit. The designated representative may submit proposed permit revisions changing the description of the actions to be taken in order for the substitution unit to achieve the maximum annual average SO_2 emissions rate under the approved plan and shall include in any such submission a showing that the actions in the changed description will not be implemented during Phase I unless the unit remains a substitution unit. The permit revision will be treated as an administrative amendment, except where the Administrator determines that the change in the description alters the fundamental nature of the actions to be taken and that public notice and comment will contribute to the decision-making process, in which case the permit revision will be treated as a permit modification or, at the option of the designated representative, a fast-track modification.

(B) The designated representative of the unit under paragraph (a)(1) of this section shall surrender allowances, and theAdministrator will deduct allowances, in accordance with paragraph (c)(5)(iii)(C) of this section. The surrender and deduction of allowances as required under the prior sentence shall be the only remedy under the Act for a failure to meet the maximum annual average SO_2 emissions rate, provided that, if such deduction of allowance results in excess emissions, the remedies for excess emissions shall be fully applicable.

* * * * *

(3) * * *

(iv)(A) If there is a change in the ownership interest of the owners or operators of any unit under a substitution plan approved as meeting the requirements of paragraph (c)(5)(i) or (ii) of this section or a change in such owners' or operators' right to direct dispatch of electricity from a substitution unit under such a plan and the demonstration under paragraph (c)(5)(i) or (ii) of this section cannot be made, then the designated representatives of the units governed by this plan shall submit a notification to terminate the plan so that the plan will terminate as of January 1 of the calendar year during which the change is made.

(B) Where a substitution plan is approved as meeting the requirements of paragraph (c)(5)(iii) of this section, if there is a change in the agreement under paragraph (c)(5)(iii) of this section and a demonstration that the agreement, as changed, meets the requirements of paragraph (c)(5)(iii) cannot be made, then the designated representative of the units governed by the plan shall submit a notification to terminate the plan so that the plan will terminate as of January 1 of the calendar year during which the change is made. Where a substitution plan is approved as meeting the requirements of paragraph (c)(5)(iii) of this section, if the requirements of the first sentence of paragraph (e)(1)(iii)(A) of this section are not met during a calendar year, then the designated representative of the units governed by the plan shall submit a notification to terminate the plan so that the plan will terminate as of January 1 of such calendar year.

(C) If the plan is not terminated in accordance with paragraphs (e)(3)(iv)(A) or (B) of this section, the Administrator, on his or her own motion, will terminate the plan and deduct the allowances required to be surrendered under paragraph (e)(3)(ii) of this section.

(D) Where a substitution unit and the Phase I unit designating the substitution unit in an approved substitution plan have a common owner, operator, or designated representative during a year, the plan shall not be terminated under paragraphs (e)(3)(iv)(A), (B), or (C) of this section with regard to the substitution unit if the year is as specified in paragraph (e)(3)(iv)(D)(*1*) or (*2*) of this section and the unit received from the Administrator for the year, under the Partial Settlement in *Environmental Defense Fund* v. *Carol M. Browner*, No. 93–1203 (D.C. Cir. 1993) (signed May 4, 1993), a total number of allowances equal to the unit's baseline multiplied by the lesser of the unit's 1985 actual SO_2 emissions rate or 1985 allowable SO_2 emissions rate.

(*1*) Except as provided in paragraph (e)(3)(iv)(D)(*2*) of this section, paragraph (e)(3)(iv)(D) of this section shall apply to the first year in Phase I for which the unit is and remains an active substitution unit.

(*2*) If the unit has a Group 1 boiler under part 76 of this chapter and is and remains an active substitution unit during 1995, paragraph (e)(3)(iv)(D) of this section shall apply to 1995 and to the second year in Phase I for which the unit is and remains an active substitution unit.

(*3*) If there is a change in the owners, operators, or designated representative of the substitution unit or the Phase I unit during a year under paragraph (e)(3)(iv)(D)(*1*) or (*2*) of this section and, with the change, the units do not have a common owner, operator, or designated representative, then the designated representatives for such units shall submit a notification to terminate the plan so that the plan will terminate as of January 1 of the calendar year during which the change is made. If the plan is not terminated in accordance with the prior sentence, the Administrator, on his or her own motion, will terminate the plan and deduct the allowances required to be surrendered under paragraph (e)(3)(ii) of this section.

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For information on briefings in Denver, CO and Washington, DC, see announcement on the inside cover of this issue.

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tables. On January 6, 1989, the Office of Management and Budget (OMB) waived Table 2 and Table 3 SIP revisions (54 FR 2222) from the requirements of Section 3 of Executive Order 12291 for 2 years. The USEPA has submitted a request for a permanent waiver for Table 2 and Table 3 SIP revisions. The OMB has agreed to continue the temporary waiver until such time as it rules on USEPA's request. This request continues in effect under Executive Order 12866 which superseded Executive Order 12291 on September 30, 1993. The OMB has exempted this regulatory action from Executive Order 12866 review.

Nothing in this action should be construed as permitting or allowing or establishing a precedent for any future request for revision to any State Implementation Plan. Each request for revision to any State Implementation Plan shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

Under the Regulatory Flexibility Act, 5 U.S.C. 600 *et seq.*, USEPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. 603 and 604. Alternatively, USEPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

SIP approvals under section 110 and subchapter I, part D of the Act do not create any new requirements, but simply approve requirements that the State is already imposing. Therefore, because the Federal SIP approval does not impose any new requirements, I certify that it does not have a significant impact on any small entities affected. Moreover, due to the nature of the Federal state relationship under the Act, preparation of a regulatory flexibility analysis would constitute Federal inquiry into the economic reasonableness of State action. The Act forbids USEPA to base its actions concerning SIPs on such grounds. *Union Electric Co.* v. *U.S. E.P.A.*, 427 U.S. 246, 256–66 (S.Ct. 1976); 42 U.S.C.7410(a)(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Incorporation by reference, Ozone.

Dated: June 30, 1994.

David A. Ullrich,

Acting Regional Administrator.

For the reasons stated in the preamble, part 52, chapter I, title 40 of the Code of Federal Regulations is amended as follows:

PART 52—[AMENDED]

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

Authority: 42 U.S.C. 7401–7671q.

Subpart P—Indiana

2. Section 52.770 is amended by adding paragraph (c)(92) to read as follows:

§ 52.770 Identification of plan.

* * * * *

(c) * * *

(92) On February 25, 1994, Indiana submitted an employee commute option rule intended to satisfy the requirements of section 182(d)(1)(B) of the Clean Air Act Amendments of 1990.

(i) *Incorporation by reference.*

(A) Title 326 of the Indiana Administrative Code, Article 19 MOBILE SOURCE RULES, Rule 1, Employee Commute Options. Filed with the Secretary of State, October 28, 1993. Effective November 29, 1993.

* * * * *

[FR Doc. 94–19909 Filed 8–17–94; 8:45 am]

BILLING CODE 6560–50–P

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40 CFR Part 75

[FRL–5040–3]

Acid Rain Program: Continuous Emissions Monitoring

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: Title IV of the Clean Air Act (the Act), as amended November 15, 1990, requires the Environmental Protection Agency (EPA or Agency) to establish an Acid Rain Program to reduce the adverse effects of acidic deposition. On January 11, 1993, the Agency promulgated final rules implementing the program, including the General Provision and Permit rule and the Continuous Emission Monitoring (CEM) rule (58 FR 3590–3766). Technical corrections were published on June 23, 1993 (58 FR 34126) and July 30, 1993 (58 FR 40746–40752). This notice of direct final rulemaking contains an extension to the certification compliance deadline for NO_x and CO_2 emissions monitoring of gas-fired units and oil-fired units affected under title IV. EPA believes that this compliance deadline extension will give the regulated community more time to meet their obligations under title IV and will allow more thorough Agency review of certification application submissions, resulting in the likelihood of higher quality data. EPA believes this deadline extension is non-controversial and therefore is publishing this notice of direct final rulemaking.

DATES: If no adverse comments are received by September 19, 1994, the effective date of these revisions will be October 17, 1994. If the effective date is delayed, timely notice will be published in the **Federal Register**.

ADDRESSES: Any written comments on these rule revisions must be identified with the document control number "A–94–16" and must be submitted in duplicate to: EPA Air Docket (6102), Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460.

FOR FURTHER INFORMATION CONTACT: Sharon Saile, CEM Section Chief, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460. (202) 233–9180.

SUPPLEMENTARY INFORMATION: In the Proposed Rules Section of this **Federal Register**, EPA is proposing to revise the Continuous Emission Monitoring provisions. The Agency views these revisions as noncontroversial and anticipates no adverse comments. However, if EPA does receive adverse comments, EPA will publish a document in the **Federal Register** withdrawing the direct final rule. All public comments received will be treated as comments on the proposed rule as published in the Proposed Rules Section of this **Federal Register** and will be addressed in a subsequent final rulemaking notice. The EPA will not institute a second comment period on the document in the Proposed Rules Section of this **Federal Register** or on any subsequent final rule addressing withdrawn portions of this final rule. Any parties interested in commenting on these revisions to Part 75 should do so at this time.

I. Acid Rain Program Background

On January 11, 1993, EPA promulgated the "core" regulations that implemented the major provisions of Title IV of the Clean Air Act Amendments of 1990 (CAAA or the Act), including the Continuous Emission Monitoring (CEM) Regulation at 40 CFR Part 75 authorized under section 412 and 821 of the Act. The CEM rule specifies how each affected utility unit must install a system to continuously monitor the emissions and to collect, record, and report emissions data to ensure that the mandated reductions in SO_2 and NO_x emissions are achieved, that opacity and CO_2 emissions are measured, and that SO_2 emissions are accurately measured so that the allowance system functions in an orderly manner.

Since the CEM rule was promulgated, the operation of Phase I utility units have essentially completed the first stage of implementation of the rule, having submitted monitoring plans, conducted certification testing, submitted certification applications, and submitted their first quarterly reports. In addition, many Phase II utility units have also begun implementation. As a result of issues arising during implementation of part 75, EPA is revising part 75 to extend the monitoring certification deadline for certain classes of units for some pollutants.

II. Changes to Part 75—Certification Deadlines for Gas-Fired and Oil-Fired Units

Affected units under title IV of the Clean Air Act Amendments are required to install and operate continuous emission monitoring systems or alternative monitoring systems approved by the Administrator. Part 75 specifies that all monitoring systems must be tested and approved through a certification process. In the January 11, 1993 final rule, EPA specified that required monitoring systems for units with emission limitations beginning January 1, 1995 (Phase I units) must be installed, operated, certified, and maintained by November 15, 1993 [40 CFR 74.4(a)(1)]. Similarly, units with emission limitations beginning January 1, 2000 (Phase II units) must be installed, operated, certified, and maintained by January 1, 1995 [40 CFR 75.4(a)(3)].

During the process of implementing part 75, the Agency learned that many utilities with Phase II units were having difficulty planning and performing certification testing early. Many utilities found the testing procedures in Appendix E sufficiently confusing that they were delaying testing for gas-fired and oil-fired peaking units. In other cases, software vendors were still assisting their Phase I unit clients and did not focus on the problems of Phase II units, causing further delays. In addition, both utilities and stack emission testing firms expressed concern that there might be a shortage of stack testers because of the large number of unit all requiring stack testing at the same time. There will be a total of approximately 1000 oil-fired and gas-fired units submitting certification applications in Phase II, compared to 5 oil-fired units in Phase I and 1300 Phase II coal-fired units compared to 263 coal-fired units in Phase I. If review of all these applications were done at the same time, the review might be severely limited because of the resources required and the short time period for review.

As a result of these concerns, the Agency is postponing the certification deadline for two categories of monitoring: NO_X and CO_2 monitoring of gas-fired and oil-fired Phase II units. Although these units must monitor NO_X and CO_2 emissions [40 CFR 75.10], they do not have NO_X emission limitations under Title IV of the Act. Gas-fired and oil-fired units are being monitored for NO_X and CO_2 to provide quality-assured NO_X and CO_2 emissions data for informational purposes. This data will also allow the Agency to assess progress toward the NO_X emission reduction goals of the Act. Furthermore, the Act requires EPA to establish a public database of CO_2 emissions data. EPA believes that delaying the certification of NO_X and CO_2 CEMS and Appendix E and G monitoring for these units still meets these purposes, and helps to ensure higher quality NO_X and CO_2 emission data than might be obtained if the January 1, 1995 deadline were still required because a phased schedule for certifications submissions will allow more thorough and complete review of the submissions for each time period. The revised deadline does not apply to coal-fired units or to monitoring of SO_2, opacity, or heat input for gas-fired and oil-fired units.

EPA believes that it is reasonable for utilities to begin to monitor the NO_X emissions in ozone nonattainment areas and the ozone transport region of the northeast U.S. earlier than in other areas. An accurate account of NO_X emissions is environmentally significant in such areas because NO_X helps ozone to form (see docket item "Title IV Affected Utility Plants in Nonattainment Areas or in OTR"). As a result, EPA is extending the certification deadline for NO_X monitoring of gas-fired and oil-fired units in ozone nonattainment areas and ozone transport regions by six months only, until July 1, 1995. Other gas-fired and oil-fired units that are not in these environmentally critical areas may postpone their certification testing until one year after the original deadline, until January 1, 1996. By instituting this phased-in approach, two purposes are accomplished—certification applications will receive thorough review and NO_X information will be available first for the areas with the greatest need for that information.

EPA has also included a delayed certification deadline for CO monitoring from oil-fired units and gas-fired units in today's revision to part 75. A CO_2 monitor may be used both as a CO_2 diluent monitor in a NO_X continuous emission monitoring system and as a CO_2 continuous emission monitoring system. If the NO_X monitoring deadline were extended but the CO_2 monitoring deadline were not extended, then the owner or operator of a gas-fired unit or and oil-fired unit would still be required to install the CO_2 monitor and stack test it before its certification as part of the NO_X monitoring system. In effect, an owner or operator would need to go through stack testing and certification twice for the same CO_2 monitor. In order to make the NO_X monitoring certification deadline extension more useful and to avoid unnecessary duplication of testing and certification activities, EPA is also extending the certification deadline for CO_2 monitoring.

Gas-fired and oil-fired peaking units may choose to use the procedures in Appendices E and G of part 75 to estimate NO_X and CO_2 emissions using means other than continuous emission monitoring. Appendix E requires a utility to develop a correlation between unit load and NO_X emission rate. Appendix G allows any utility, not just peaking units, to estimate CO_2 mass emissions from a unit using fuel sampling and analysis and fuel usage data. Both of these methods require the development of software that is different from that already developed and implemented for use under Phase I of the program. In contrast, software programmers have already developed software for units with continuous emission monitoring systems and for units using Appendix D of part 75 for determination of SO_2 emissions from oil-fired or gas-fired units. In order to allow software programmers more time to develop software to implement Appendices E and G of part 75, EPA is extending the certification deadline for NO_X monitoring and CO_2 monitoring from these methods, as well as for CEMS.

EPA is not extending the certification deadlines for coal-fired units. Phase I utilities overwhelmingly were able to meet the statutory deadline for monitoring with CEMS—95% of Phase I units completed testing by the deadline of November 15, 1993. There are no class-wide issues delaying implementation for coal-fired units using CEMS. Therefore, EPA expects that all Phase II coal-fired units will meet the certification deadline of 1/1/95. Furthermore, coal-fired units have emission limitations for SO_2 and NO_x under the Acid Rain Program. Coal-fired units emit large amounts of SO_2 and NO_x.

EPA also is not extending the certification deadlines for SO_2 and opacity monitoring for gas-fired units and oil-fired units. Gas-fired and oil-fired units have SO_2 emission reduction obligations under title IV of the Act. Oil-fired units, in particular, have significant SO_2 emissions. Many of these units have the opportunity to implement Appendix D of part 75 (an optional SO_2 emissions estimation protocol using fuel sampling and analysis), thereby avoiding stack testing for CEMS. Some Phase I units were oil-fired units using Appendix D. The Agency has issued guidance to the regulated community that allows them to implement Appendix D. Furthermore, software has already been developed to implement Appendix D requirements. Opacity monitors do not require the services of special stack testers or new software. Extending the deadline for SO_2 and opacity monitoring for gas-fired units and oil-fired units will not reduce competition for stack testers or require development of software that has not been developed for Phase I units. Because of these reasons, EPA expects gas-fired units and oil-fired units to meet the January 1, 1995 certification deadline for SO_2 and opacity monitoring.

III. Impact Analyses

A. Paperwork Reduction Act

EPA has determined that this final rule contains no information requirements as specified by the Paperwork Reduction Act 44 U.S.C. 3501 *et seq.*

B. Executive Order Requirements

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 OMB review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to results in a rule that may:

(1) Have an annual effect on the economy of $100 million of 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.

C. Regulatory Flexibility Act

Pursuant to section 605(b) of the Regulatory Flexibility Act, 5 U.S.C. 605(b), the Administrator certifies on August 4, 1994, that this rule revision will not have a significant economic impact on a substantial number of small entities.

EPA performed an analysis of the effects upon small utilities of the Acid Rain Core Rules (58 FR 3649, January 11, 1993), including permitting, allowances, and continuous emission monitoring. The earlier document concluded that significant costs would occur to small utilities as a result of statutory requirements. For example, based upon a worst case for model utilities, total regulatory costs could represent as much as 6 to 7 percent of the average value of electricity produced in the year 2000. About one-third of the 105 small utilities currently affected could face impacts of up to this magnitude.

Today's revisions to part 75 have either no impact or a beneficial impact on small entities by extending the time for complying with the Acid Rain Program monitoring requirements for approximately 800 small utility units. EPA expects today's revision to part 75 to maintain the same cost of compliance as under the promulgated rule of January 11, 1993.

IV. Supporting Information

List of Subjects in 40 CFR Part 75

Environmental protection, Air pollution control, Carbon dioxide, Continuous emission monitors, Electric utilities, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: August 4, 1994.

Carol M. Browner,

Administrator, U. S. Environmental Protection Agency.

For the reasons set forth in the preamble chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 75—CONTINUOUS EMISSION MONITORING

1. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7651k and note.

Subpart A—General [Amended]

2. Section 75.4 is amended by revising paragraph (a)(3) to read as follows:

§ 75.4 Compliance dates.

(a) * * *

(3) For either a Phase II unit, other than a gas-fired unit or an oil-fired unit, or a substitution or compensating unit that is not a substitution or compensating unit under paragraph (a)(2) of this section: January 1, 1995.

* * * * *

3. Section 75.4 is amended by adding paragraph (a)(4) to read as follows:

(a) * * *

(4) For a gas-fired Phase II unit or an oil-fired Phase II unit, January 1, 1995, except that certification tests for continuous emission monitoring systems for NO_X and CO_2 or excepted monitoring systems for NO_X under appendix E or CO_2 estimation under Appendix G of this part shall be completed as follows:

(i) For an oil-fired Phase II unit or a gas-fired Phase II unit located in an ozone nonattainment area or the ozone transport region, not later than July 1, 1995; or

(ii) For an oil-fired Phase II unit or a gas-fired Phase II unit not located in an ozone nonattainment area or the ozone transport region, not later than January 1, 1996.

* * * * *

[FR Doc. 94-20167 Filed 8-17-94; 8:45 am]
BILLING CODE 6560-50-P

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40 CFR Part 180

[PP 0E3859/R2077; FRL-4907-3]

RIN 2070-AB78

Procymidone; Pesticide Tolerance for Wine Grapes

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This document establishes a permanent tolerance for residues of the

fungicide procymidone, N-(3,5-dichlorophenyl)-1,2-dimethylcyclopropane-1,2-dicarboximide, in or on the raw agricultural commodity (RAC) wine grapes at 5.0 parts per million (ppm). Sumitomo Chemical Co., Ltd., petitioned EPA to establish this regulation setting the maximum permissible level for residues of procymidone in or on wine grapes.

EFFECTIVE DATE: This regulation becomes effective August 12, 1994.

ADDRESSES: Written objections, identified by the document control number, [PP 0E3859/R2077], may be submitted to: Hearing Clerk (1900), Environmental Protection Agency, Rm. M3708, 401 M St., SW., Washington, DC 20460. A copy of any objections and hearing requests filed with the Hearing Clerk should be identified by the document control number and submitted to: Public Response and Program Resources Branch, Field Operations Division (7506C), Office of Pesticide Programs, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. In person, bring copy of objections and hearing requests to: Rm. 1132, CM #2, 1921 Jefferson Davis Hwy., Arlington, VA 22202. Fees accompanying objections shall be labeled "Tolerance Petition Fees" and forwarded to: EPA Headquarters Accounting Operations Branch, OPP (Tolerance Fees), P.O. Box 360277M, Pittsburgh, PA 15251.

FOR FURTHER INFORMATION CONTACT: By mail: Steve Robbins, Acting Product Manager (PM) 21, Registration Division (7505C), Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Office location and telephone number: Rm. 227, 1921 Jefferson Davis Hwy., Arlington, VA 22202, (703)-305-6900.

SUPPLEMENTARY INFORMATION: In the **Federal Register** of March 31, 1994 (59 FR 15145), EPA issued a proposed rule that gave notice that the Sumitomo Chemical Co., Ltd., had petitioned EPA under section 408 of the Federal Food, Drug, and Cosmetic Act, 21 U.S.C. 346a, to establish a permanent tolerance for procymidone in or on wine grapes at 5.0 ppm. Because EPA has added additional documentation to the public docket on the proposed tolerance under section 408 of the Federal Food, Drug and Cosmetic Act (21 U.S.C. 346a) for residues of the fungicide procymidone on wine grapes, EPA reopened and extended for 30 days the comment period on the proposed rule. The announcement of the reopening/extension was published in the **Federal** Register of June 30, 1994 (59 FR 33723).

I. Commments on the Proposal

In response to the March 31, 1994 proposed rule, seven comments were received.

1. Four comments supported establishing a permanent tolerance.

2. The National Coalition Against the Misuse of Pesticides (NCAMP) lodged a five-point comment addressing enforceability of the tolerance, the risk assessment, the exposure calculation, the Agency's tolerance-setting procedures, and international trade versus health concern issues. The paraphrased comments and the EPA responses follow:

NCAMP Comment 1. EPA is proposing an unenforceable tolerance. EPA is setting a tolerance on grapes to be used in imported wine, not on the wine itself. We believe that the EPA, with the information it now has, is unable to make determinations about the residues on the grapes. At no time do the grapes themselves enter the U.S. or come within its legal arm. A tolerance which cannot be regulated or enforced is meaningless and not protective of public health and the environment. The tolerance should be set on the product that can be regulated, i.e., the wine.

EPA's Response. NCAMP is mistaken on the enforceability of the procymidone tolerance for wine grapes. This tolerance is fully enforceable against wine. Wine containing procymidone residues at a level greater than the 5-ppm wine grape tolerance would be adulterated as a matter of law under the FFDCA. See 21 U.S.C. 342(a)(2). Any other commodity found to contain residues of procymidone, including fresh table grapes, grape juice, and raisins, would be considered adulterated and subject to seizure by the FDA. Moreover, EPA does have adequate data on procymidone residues in wine grapes. Field trial data from 39 locations in France, Germany, Hungary, Italy, Spain, Bulgaria, Australia, Argentina, and Chile (multiple plots in some locations) were submitted for review and were determined overall to reflect adequately the use patterns of procymidone. Wine grapes were treated at 1 to 2 times the maximum label rate, which varied by location (typical 1 X rate was 0.7 lb ai/A/yr, multiple applications), according to label directions. Grape samples were harvested at Post Harvest Intervals (PHIs) generally ranging from 5 to 28 days and analyzed for procymidone. Details of the analyses and storage stability data were submitted and adequately support the residue data. The appropriate tolerance level for wine grapes was determined to be 5 ppm.

NCAMP Comments 2 and 3. EPA conducted a risk assessment on wine grapes assuming residues at less than half the proposed legal limit. It is not protective of the public health to set a tolerance at a level at which the effects are unknown. EPA used averages to calculate exposure. Procymidone residues may concentrate when grapes are processed into wine. Finally, EPA should have considered individuals and groups who consume greater than "average" amounts of wine and individuals who are more sensitive to pesticide exposures.

EPA's Responses. A residue level of 2.4 ppm was used to estimate chronic dietary and cancer risks. Since imported wine grapes will not be directly consumed, and study data indicate that residues of procymidone are significantly reduced upon processing to wine, use of the tolerance level of 5.0 ppm would have produced unrealistic estimates. Therefore, a typical, or anticipated, residue level of 2.4 ppm supported by the field trial data on wine grapes was used to estimate dietary risks. Some data on levels in wine were submitted, but were fewer in quantity, in comparison to the field trial data. EPA routinely performs chronic and cancer risk estimates using anticipated residues since tolerance levels do not reflect actual or typical residue levels found in foods. Averaging of residue levels (here, an average from field trials using maximum application rates) is appropriate for estimating chronic risks because with chronic risks, EPA is concerned with exposure over a person's lifetime. Over a lifetime, exposure will likely be an average of the range of residue values, not the high end residue value. Moreover, averaging is particularly appropriate where the food through which most exposure will occur (here, wine) results from the blending of the commodity.

In addition to the study data submitted for the Agency's consideration, FDA monitoring data also suggest that the actual residue levels in wine will be even lower. During 1990, when procymidone residues were first detected in wine, FDA analyzed approximately 1,100 imported wine samples. The highest level found was 0.6 ppm. The incidence of positive samples (greater than 0.02 ppm) was 9%, and the average positive finding was 0.06 ppm. A time-limited tolerance of 7 ppm was established on April 26, 1991 (56 FR 19518) for wine grapes grown in 1989 or before. FDA continued to monitor wine for procymidone residues in 1991. A total of 501 samples