required sample of fuel carbon content are either missing or invalid. The substitute data value shall be used until the next valid carbon content sample is obtained.

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Sampling technique/frequency	Missing data value
Oil and coal carbon content	All oil and coal samples, prior to April 1, 2000.	Most recent, previous carbon content value available for that grade of oil, or default value, in this table.
Gas carbon content	All gaseous fuel samples, prior to April 1, 2000.	Most recent, previous carbon content value available for that type of gaseous fuel, or default value, in this table.
Default coal carbon content	All, on and after April 1, 2000	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	All, on and after April 1, 2000	90.0 percent.
Default gas carbon content	All, on and after April 1, 2000	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO_2 emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

[58 FR 3701, Jan. 11, 1993, as amended at 60 FR 26556-26557, May 17, 1995; 61 FR 25585, May 22, 1996; 64 FR 28671, May 26, 1999]

APPENDIX H TO PART 75—REVISED TRACEABILITY PROTOCOL NO. 1 [RESERVED]

APPENDIX I TO PART 75—OPTIONAL F—FACTOR/FUEL FLOW METHOD [RESERVED]

APPENDIX J TO PART 75—COMPLIANCE DATES FOR REVISED RECORDKEEPING REQUIREMENTS AND MISSING DATA PROCEDURES [RESERVED]

[60 FR 26557, May 17, 1995]

PART 76—ACID RAIN NITROGEN OXIDES EMISSION REDUCTION PROGRAM

Sec.

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

SOURCE: 60 FR 18761, Apr. 13, 1995, unless otherwise noted.

§ 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.

Arch-fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are at an angle significantly different from the horizontal axis and the vertical axis. This definition shall include only the following units: Holtwood unit 17, Hunlock unit 6, and Sunbury units 1A, 1B, 2A, and 2B. This definition shall exclude dry bottom turbo fired boilers.

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 during the following calendar year: for Phase I units, in calendar year 1990; and, for Phase II units, in calendar year 1995 or, for a Phase II unit that did not combust any fuel that resulted in the generation of electricity in calendar year 1995, in any calendar year during the period 1990–1995. For the purposes of this part, this definition shall apply notwithstanding the definition in § 72.2 of this chapter.

Combustion controls means technology that minimizes NO_X formation by staging fuel and combustion air flows in a boiler. This definition shall include low

NO_X burners, overfire air, or low NO_X burners with overfire air.

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).

Maximum Continuous Steam Flow at 100% of Load means the maximum capacity of a boiler as reported in item 3 (Maximum Continuous Steam Flow at 100% Load in thousand pounds per hour), Section C (design parameters), Part III (boiler information) of the Department of Energy's Form EIA–767 for 1995.

Non-plug-in combustion controls means the replacement, in a cell burner boiler, of the portions of the waterwalls containing the cell burners by new portions of the waterwalls containing low NO_X burners or low NO_X burners with overfire air.

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.

Plug-in combustion controls means the replacement, in a cell burner boiler, of existing cell burners by low NO_X burners or low NO_X burners with overfire air.

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.

Vertically fired boiler means a dry bottom boiler with circular burners, or coal and air pipes, oriented downward and mounted on waterwalls that are horizontal or at an angle. This definition shall include dry bottom roof-fired boilers and dry bottom top-fired boilers, and shall exclude dry bottom arch-fired boilers and dry bottom turbo-fired boilers.

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 that the ash is removed from the furnace in a molten state. The term ''wet bottom boiler'' shall include: wet bottom wall-fired boilers, including wet bottom turbo-fired boilers; and wet bottom boilers otherwise meeting the definition of vertically fired boilers, including wet bottom arch-fired boilers, wet bottom roof-fired boilers, and wet bottom top-fired boilers. The term ''wet bottom boiler'' shall exclude cyclone boilers and tangentially fired boilers.

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67162, Dec. 19, 1996]

§ 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.

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67162, Dec. 19, 1996]

§ 76.6 NO_X emission limitations for Group 2 boilers.

(a) Beginning January 1, 2000 or, for a unit subject to section 409(b) 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 Group 2, coal-fired boiler with a cell burner boiler, cyclone boiler, a wet bottom boiler, or a vertically fired boiler 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 §§ 76.10 or 76.11:

(1) 0.68 lb/mmBtu of heat input on an annual average basis for cell burner boilers. The NO_X emission control technology on which the emission limitation is based is plug-in combustion controls or non-plug-in combustion controls. Except as provided in § 76.5(d), the owner or operator of a unit with a cell burner boiler that installs non-plug-in combustion controls shall comply with the emission limitation applicable to cell burner boilers.

(2) 0.86 lb/mmBtu of heat input on an annual average basis for cyclone boilers with a Maximum Continuous Steam Flow at 100% of Load of greater than 1060, in thousands of lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(3) 0.84 lb/mmBtu of heat input on an annual average basis for wet bottom boilers, with a Maximum Continuous Steam Flow at 100% of Load of greater than 450, in thousands of lb/hr. The NO_X emission control technology on which the emission limitation is based is natural gas reburning or selective catalytic reduction.

(4) 0.80 lb/mmBtu of heat input on an annual average basis for vertically fired boilers. The NO_X emission control technology on which the emission limitation is based is combustion controls.

(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.

[62 FR 67162, Dec. 19, 1996; 62 FR 3464, Jan. 23, 1997; 62 FR 32040, June 12, 1997; 64 FR 55838, Oct. 15, 1999]

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

(a) 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 dry bottom wall-fired boiler 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 §§ 76.8, 76.10, or 76.11:

(1) 0.40 lb/mmBtu of heat input on an annual average basis for tangentially fired boilers.

(2) 0.46 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.

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67163, Dec. 19, 1996]

§ 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 § 76.7 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 § 76.7.

(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 §76.7.

(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 §76.7.

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67163, Dec. 19, 1996]

§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.

(2) [Reserved]

(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 §76.6 or 76.7 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).

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67163, Dec. 19, 1996]

§ 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:

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

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 thecalendar 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:

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

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:

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

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_l 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_l, 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,

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

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).

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.
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.

TABLE 1—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
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.
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.

TABLE 1—PHASE I TANGENTIALLY FIRED UNITS—Continued

State	Plant	Unit	Operator
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.
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.

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

State	Plant	Unit	Operator
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, 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 cost in constant dollars of low NO_X burner technology applied to Group 1, Phase I boilers.

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 capital costs and cost effectiveness for Group 1, Phase I boilers. The following units will be excluded from these determinations of the capital costs 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 overfire air as applied to wall-fired boilers or 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 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 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.

3. [Reserved]

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.

[60 FR 18761, Apr. 13, 1995, as amended at 61 FR 67164, Dec. 19, 1996; 62 FR 3464, Jan. 23, 1997]

PART 77—EXCESS EMISSIONS

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

SOURCE: 58 FR 3757, Jan. 11, 1993, unless otherwise noted.

§77.1 Purpose and scope.

(a) This part sets forth the excess emissions offset planning and offset penalty requirements under section 411 of the Clean Air Act, 42 U.S.C. 7401, *et seq.*, as amended by Public Law 101–549 (November 15, 1990). These requirements shall apply to the owners and operators and, to the extent applicable, the designated representative of each affected unit and affected source under the Acid Rain Program.

(b) Nothing in this part shall limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act, as amended. Any allowance deduction, excess emission penalty, or interest required under this part shall not affect the liability of the affected unit's and affected source's owners and operators for any additional fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Act.

§77.2 General.

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

§77.3 Offset plans for excess emissions of sulfur dioxide.

(a) *Applicability*. The owners and operators of any affected unit that has excess emissions of sulfur dioxide in any calendar year shall be liable to offset the amount of such excess emissions by an equal amount of allowances from the unit's Allowance Tracking System account.

(b) *Deadline.* Not later than 60 days after the end of any calendar year during which an affected unit had excess emissions of sulfur dioxide (except for any increase in excess emissions under §72.91(b) of this chapter), the designated representative for the unit shall submit to the Administrator a complete proposed offset plan to offset those emissions. Each day after the 60-day deadline that the designated representative fails to submit a complete proposed offset plan shall be a separate violation of this part.

(c) *Number of Plans.* The designated representative shall submit a proposed offset plan for each affected unit with excess emissions of sulfur dioxide.

(d) *Contents of Plan*. A complete proposed offset plan shall include the following elements in a format prescribed by the Administrator for the unit and for the calendar year for which the plan is submitted:

(1) Identification of the unit.

(2) If the unit had excess emissions for the calendar year prior to the year for which the plan is submitted, an explanation of how and why the excess emissions occurred for the year for which the plan is submitted and a description of any measures that were or will be taken to prevent excess emissions in the future.

(3) At the designated representative's option, the number of allowances to be deducted from the unit's Allowance Tracking System account to offset the excess emissions for the year for which the plan is submitted.

(4) At the designated representative's option, the serial numbers of the allowances that are to be deducted from the