RULES AND REGULATIONS

Title 25—ENVIRONMENTAL PROTECTION

ENVIRONMENTAL QUALITY BOARD

[25 PA. CODE CHS. 121 AND 123]

Nitrogen Oxides Allowance Requirements

The Environmental Quality Board (Board) by this order amends Chapters 121 and 123 (relating to general provisions; and standards for contaminants) as set forth in Annex A. The final-form regulations establish a program to limit the emission of nitrogen oxides (NO_x) from fossil-fired combustion units with rated heat input capacity of 250 MMBtu/hour or more and electric generating facilities of 15 megawatts or greater.

The order was adopted by the Board at its meeting of September 16, 1997.

A. *Effective Date*

These amendments will go into effect upon publication in the *Pennsylvania Bulletin* as final rulemaking.

B. *Contact Persons*

For further information, contact J. Wick Havens, Chief, Division of Air Resources Management, Bureau of Air Quality, 12th Floor Rachel Carson State Office Building, P. O. Box 8468, Harrisburg, PA 17105-8468 (717) 787-4310, or M. Dukes Pepper, Jr., Assistant Counsel, Bureau of Regulatory Counsel, Office of Chief Counsel, 9th Floor Rachel Carson State Office Building, P. O. Box 8464, Harrisburg, PA 17105-8464 (717) 787-7060. Persons with a disability may use the AT&T Relay Service by calling (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). These regulations are available electronically through the Department of Environmental Protection (Department) Web site (http://www.dep.state.pa.us).

C. *Statutory Authority*

This action is being taken under the authority of section 5(a)(1) of the Air Pollution Control Act (35 P. S. § 4005(a)(1)), which grants to the Board the authority to adopt regulations for the prevention, control, reduction and abatement of air pollution.

D. *Background and Summary*

In the 1990 amendments to the Federal Clean Air Act, Congress recognized that ground level ozone (smog) is a regional problem not confined to state boundaries. Section 184 of the Clean Air Act (42 U.S.C.A. § 7511c), establishes the Northeast Ozone Transport Commission (OTC) to assist in developing recommendations for the control of interstate ozone air pollution.

Ozone is not directly emitted by pollution sources but is created as a result of the chemical reaction of NO_x and volatile organic compounds (VOCs), in the presence of light and heat, to form ozone in the air masses traveling over long distances. Exposure to ozone causes decreased lung capacity, particularly in children and elderly individuals. Decreased lung capacity from ozone exposure can frequently last several hours after the initial exposure. All states in the Northeast Ozone Transport Region, except for Vermont, have, since 1990, experienced levels of ozone during the months of May through September in excess of the National ambient air quality standard.

Because NO_x from large fossil-fired combustion units is a major contributor to regional ozone pollution, the OTC member states, including this Commonwealth, proposed development of a regional approach to address NO_x emissions. Beginning in 1993, the Northeast States for Coordinated Air Use Management (NESCAUM), the Mid-Atlantic Regional Air Management Association (MARAMA) and the United States Environmental Protection Agency (EPA) began working with the OTC to study the feasibility of implementing regional NO_x emission reductions utilizing an emission budget program in the northeast. Regional airshed modeling was used to identify the appropriate level of emission reductions that would contribute to a significant improvement in air quality.

As a result of these evaluations, the OTC proposed two additional phases of NO_x emissions reduction beyond that already achieved by the Reasonably Available Control Technology (RACT) Program. This recommendation was formally adopted by the OTC in a Memorandum of Understanding (OTC MOU) in September of 1994. The OTC states, in the MOU of September 27, 1994, agreed to propose regulations for the control of NO_x emissions in accordance with the following guidelines:

1. The level of NO_x required would be established from a 1990 baseline emissions level.

2. The reduction would vary by location, or zone, and would be implemented in two phases utilizing a regionwide trading program.

3. The reduction would be determined based on the less stringent of the following:

a. By May 1, 1999, the affected facilities in the inner zone shall reduce their combined rate of NO_x emissions by 65%, or emit NO_x at a rate no greater than 0.20 pounds per million Btus.

b. By May 1, 1999, the affected facilities in the outer zone shall reduce the combined rate of NO_x emissions by 55% from baseline, or shall emit NO_x at a rate no greater than 0.20 pounds per million Btu.

c. By May 1, 2003, the affected facilities in the inner and outer zones shall reduce their combined rate of NO_x emissions by 75% from baseline, or shall emit NO_x at a rate no greater than 0.15 pounds per million Btu.

d. By May 1, 2003, the affected facilities in the northern zone shall reduce their combined rate of NO_x emissions by 55% from baseline, or shall emit NO_x at a rate no greater than 0.20 pounds per million Btu.

In this Commonwealth, the counties of Berks, Bucks, Chester, Delaware, Montgomery and Philadelphia are in the inner zone; the remaining counties in this Commonwealth are in the outer zone.

Under section 7.4 of the Air Pollution Control Act (35 P. S. § 4007.4), the control strategies approved by the OTC and by the Commonwealth's representatives set forth in the OTC MOU are commitments by the Department to pursue regulatory actions under state law to implement the control strategies. To provide for the optimal degree of flexibility and to minimize compliance costs, the Department joined with the member states of the OTC to develop a regionwide market-based "cap and trade" program. A "cap and trade" program sets a regulatory limit on mass emissions from a discreet group of sources, allocates allowances to the sources authorizing emissions up to the regulatory limit, and permits trading of allowances to effect cost efficient compliance with the cap.

To ensure that the OTC states included common elements in the rules implementing the OTC MOU, the states worked through NESCAUM, MARAMA and the EPA to develop a model rule containing the common program elements. In addition to the State and Federal representatives, the NESCAUM, MARAMA NO_x budget task force was joined by an ad hoc committee comprised of representatives from industry, utilities and environmental groups to ensure broad-based participation and consensus in the model rule.

The task force and ad hoc committee recognized that state program consistency is critical to the overall success of the NO_x allowance program. State programs that are substantively identical in key areas will ensure that a ton of emissions reduced in one state is equivalent to a ton reduced in another state. Since states desire to promote cost effective compliance through intrastate and interstate emission trading, this level of consistency is essential to an effective trading program. The NESCAUM/MARAMA Model Rule meets these objectives and represents substantial consensus among the State and Federal governmental representatives and the ad hoc committee members on key regulatory elements of a NO_x allowance program to implement the OTC MOU. The Model Rule applies to fossil-fired combustion units with a rated capacity of 250 MMBtu/hour or more and electric generating facilities of 15 megawatts or greater. Under the program, the OTC MOU emission reductions are applied to a 1990 baseline for NO_x emissions in the ozone transport region to create a "cap" on the emissions budget for each of the two target years: 1999 and 2003. The 1990 baseline was established through extensive work of the OTC, EPA and industry to refine and quality assure the data available on actual NO_x emissions for 1990. The 1990 emissions and budget for the OTC region has been desegregated to a state level and the states are allocating allowances to the facilities in the program. Beginning in 1999, the sum of NO_x emissions from NO_x affected sources during the May 1 through September 30 control period cannot exceed the equivalent number of allowances allocated in the region. An allowance is equal to 1 ton of NO_x emissions. NO_x affected sources must hold allowances for all NO_x emitted during the ozone season months of May through September and NO_x affected sources are allowed to buy, sell or trade allowances as needed.

These final-form regulations are part of the Commonwealth's SIP to meet the reasonable further progress and attainment requirements of the Clean Air Act. In addition, the final-form regulations are proposed as being comparable with and in lieu of implementation of Stage II vapor recovery system requirements throughout the State. As a comparable measure, it will satisfy the requirements under section 184(b)(2) of the Clean Air Act (42 U.S.C.A. § 7511c(b)(2)). A SIP amendment implementing the Stage II comparability provisions will be submitted to the EPA at a later date.

Finally, as part of the "considerations and current assumptions" as outlined in the *Operating Agreements for Stakeholder Deliberations*, Southwestern and Southeastern Pennsylvania Ozone Stakeholder Groups recognized that Phase II of the Northeast Ozone Transport Commission's NO_x MOU would be adopted by the Commonwealth as a NO_x reduction strategy. Therefore, the 55% and 65% reductions in NO_x from utility, IPP and other large industrial boilers (that are subject to Phase II of the NO_x MOU) have been understood to be one of the precursor reduction options in the attainment strategy modeled for the Pittsburgh-Beaver Valley and Philadelphia Ozone Nonattainment Areas.

The AQTAC has been intimately involved in the allocation of allowances to budgeted sources and the development of both the model rule and these final-form regulations. On July 22, 1997, the AQTAC recommended that the Department proceed with the final-form regulations including the allocation methodology for individual sources.

The amendments establish definitions for the following terms: "account," "account number," "acquiring account," "compliance account," "electric generating facility," "fossil fuel," "fossil fuel fired," "general account," "heat input," "indirect heat exchange combustion unit," "maximum heat input capacity," "NO_x affected source," "NO_x allocation," "NO_x allowance," "NO_x allowance deduction," "NO_x allowance continuous emissions monitoring system (NO_x allowance CEMS)," "NO_x allowance control period," "NO_x allowance curtailment," "NO_x allowance tracking system (NATS)," "NO_x allowance transfer," "NO_x allowance transfer deadline," "NO_x budget," "NO_x budget administrator," "NO_x emissions tracking system (NETS)," "Ozone Transport Commission Memorandum Of Understanding (OTC MOU)" and "replacement source."

These defined terms are used in the substantive provisions contained in Chapter 123.

This rulemaking implements the NO_x MOU in a manner consistent with the NESCAUM/MARAMA Model Rule. The proposal identifies each known facility and each source within the facility subject to the rule along with the allowance allocation for the May 1 through September 30 control period in Appendix A. The rule also describes the process and procedure for transferring allowances between NO_x affected sources in §§ 123.106 and 123.107 (relating to NO_x allowance transfer protocol; and NO_x allowance transfer procedure). The compliance requirements for sources and the remedy in the event the sources fail to comply are described in §§ 123.110 and 123.111 (relating to source compliance requirements; and failure to meet source compliance requirements).

Because this proposal is dependent upon accurate tracking of NO_x emissions, the interstate NO_x Allowance Tracking System (NATS) is established along with procedures for tracking emissions in §§ 123.104 and 123.105(relating to source authorized account representative requirements; and NATS provisions). The source monitoring, recordkeeping and reporting requirements contained in §§ 123.108, 123.109 and 123.113 (relating to source emissions monitoring requirements; source emissions reporting requirements; and source recordkeeping requirements) detail the methodology that NO_x affected sources must follow to accurately characterize and report NO_x emissions during the control period.

Sections 123.116 and 123.117 (relating to source opt-in provisions; and new NO_x affected source provisions) describe the mechanism for including additional sources in the NO_x allowance program. Section 123.116 describes the procedure for sources to opt into the program and obtain an allowance allocation. Section 123.117 describes the process for both new sources meeting the thresholds for regulation and newly identified sources.

Because the NO_x affected sources are all "major sources" for purposes of the new source review program contained in Chapter 127, Subchapter E (relating to new source review), modifications of these sources that increase their potential to emit above new source review thresholds or the addition of a new source above the new source review threshold will require both emission reduction credits and NO_x allowances. Section 123.118 (relating to emission reduction credit provisions) describes the relationship between the emission reduction credit provisions and the NO_x allowance program provisions.

Finally, § 123.120 (relating to audit) establishes an audit program to evaluate the effectiveness of the emission reductions achieved under the NO_x allowance program. If the audit identifies problems with the program, the program regulations will be amended to address those problems.

Because some sources may be willing to make reductions in emissions prior to the time the rule becomes finalized, § 123.119 (relating to bonus NO_x allowance awards) allows those sources to receive bonus NO_x allowances. This will encourage early control and increased environmental benefits.

E. *Summary of Comments and Responses on the Proposed Rulemaking*

The Department received 39 sets of comments on the regulatory proposal. The following discussion summarizes the major issues and the Department's response.

Many commentators raised questions and concerns about both the allocations of allowances to independent power producers in Appendix A and the special provisions for independent power producers contained in § 123.121 (relating to additional requirements for independent power procedures). The Department has incorporated the recommendation of the AQTAC for allocating allowances to independent power producers. In addition, based on the comments received, the Department has deleted the provisions of § 123.121 related to independent power producers. This group of sources are the best controlled NO_x affected units subject to this program and provide additional environmental benefits based on the fuel used to fire these units. The Department does not believe that restricting these units' ability to use allowances is appropriate. The AQTAC recommended that the Department retain § 123.21.

In addition, the Department strongly disagrees with the assertion by a number of commentators that the allocations made to the independent power producers were taken from other sources. No one has a right to emit air pollutants into the outdoor atmosphere. The Department, through these final-form regulations, is establishing emission limitations for NO_x affected sources using a cap and trade program. Allowances made to the sources are a limited authorization to emit NO_x and do not represent a property right.

A number of commentators expressed concerned about the monitoring requirements and particularly the differences between the monitoring required under this program and the monitoring required by Chapter 139 (relating to sampling and testing). The Department does not intend to require separate data handling systems or other monitoring duplications for NO_x affected sources in order to meet monitoring provisions. To make this clear, the Department has modified § 123.108 to require compliance with the monitoring provisions of this rule in a manner consistent with Chapter 139. The Department will work with NO_x affected sources to address any data reporting and handling issues that arise.

A number of commentators provided specific information about either the 1990 inventory data or the allowance calculations applicable to the sources. The Department has modified the inventory and allocations as appropriate in Appendix A. In addition, the Department added additional provisions in § 123.115 (relating to initial NO_x allowance NO_x allocations) to address comments made by Duquesne Light Company related to two of their facilities.

A number of commentators expressed concern about the audit program. Specifically, they were concerned that the Department could modify the allocation and other components of the program without a regulatory amendment. In response to these comments, the Department has revised the audit provisions in § 123.120 to delete the authority to modify the allocations and program requirements without a regulatory change.

Most commentators supported the opt-in provisions in § 123.116. However, some object to the provision concerning the shutdown or curtailment of operations. The Department has retained the opt-in provisions contained in the proposed rule.

A number of commentators suggested that allowances from shutdown NO_x affected sources be made available to new NO_x affected sources. The Department has not implemented that recommendation. The recommendation would be inconsistent with the OTC model rule and would have a negative impact on the market based trading approach. The Department treats shutdown sources for NO_x allowances in the same way as under the new source review program for emission reduction credits.

A number of commentators suggested that the Department follow the OTC model rule procedures for approving bonus allowances. The Department has modified the language in § 123.119 to incorporate the model rule provisions and to make it clear that bonus allowances can only be generated for reductions that go beyond otherwise applicable requirements.

The Department received a number of comments concerning the banking provisions in § 123.110. Many in the utility industry opposed the flow control requirements in the regulation and proposed an alternative mechanism. Comments from environmental groups suggested that the Department establish daily emission caps and limit multi-year banking. They assert that unused allowances created in cool summers could be used to allow emissions in hot summers when ozone exceedances are more likely. They were concerned that the banking provisions and lack of a daily cap seriously undermined the environmental benefits of this rule. The Department has retained the banking provisions and has made a clarifying amendment to § 123.110.

Several commentators objected to the enforcement provisions of the regulations. These final-form regulations provide a great detail of flexibility for sources to comply with the requirements. Consequently, sources operating in a conscientious fashion should not have compliance problems. The enforcement provisions provide a significant deterrent to sources and will enhance the integrity of the program. These enforcement provisions which are consistent with the model rule, have been retained. The AQTAC recommended relaxation of these provisions.

A number of commentators raised questions or concerns about the relationship between NO_x allowances and emission reduction credits. In addition, some commentators asserted that the Department's proposal was too restrictive while others believe that it allowed double counting. The Department has modified § 123.118 to clarify the intent of this section and to make it clear that double counting cannot occur.

The EPA asserted that the economic incentive policy guidelines are applicable to this program. They requested a demonstration that the regulations met these program guidelines. The Department plans to continue working with the EPA to address this issue.

The EPA asked that a formal SIP for Stage II comparability be developed. The Department plans to develop a Stage II comparability SIP submission in the near future.

The Department received a number of comments concerning the discussion in the Preamble to the proposal related to implementation of the program. Some commentators believe the program should not be implemented until similar programs are required in other states; other commentators believe the program should be implemented independent of other state requirements. Implementation of this program is necessary to meet the Department's commitments to ozone attainment in both Philadelphia and Pittsburgh. This regulatory program was one of the core programs recognized by both the Southwest and Southeast Ozone Stakeholder Working Groups as necessary for Pennsylvania to attain the NAAQS for ozone. Consequently, the Department is proposing that these amendments become final upon publication in the *Pennsylvania Bulletin*.

In addition to these major substantive changes, the Department has made a number of clarifying amendments to §§ 121.1, 123.102—123.106 and 123.108—123.119.

F. *Benefits, Cost and Compliance*

Executive Order 1996-1 requires a cost/benefit analysis of the amendments. Overall, the citizens of this Commonwealth will benefit from the amendments because they will provide appropriate protection of air quality both in this Commonwealth and the entire Northeastern United States. In addition to reducing ozone pollution, this program will assist the Commonwealth in meeting its requirements for reasonable further progress and Stage II comparability under the Clean Air Act.

These final-form regulations are expected to result in public health cost savings of $35—730 million dollars per year from ozone reductions and $120 million dollars per year resulting from reductions in particulate matter emissions.

Worker health care costs and productivity should yield cost savings, as well as the welfare benefits, and decreased structural deterioration of concrete, paints and metals should also result in benefits.

A control technology cost analysis of the public electric utility industry was conducted by the Department. Over 95% of the affected sources are electric generating utilities. Using the worst case $42 million per year estimate, the cost of generation is expected to increase by approximately 1.2% using 1995 technology cost data. Recent developments in control technology have demonstrated large cost reductions on the order of 50% for this level of emission reduction since this estimate was completed. The total cost without trading based on 1995 data was $60 million per year, trading will reduce this by one third to $42 million per year. Substantiating this estimate, the OTAG completed cost studies in October of 1996 showing that the cost of reducing emissions to a much lower standard, 0.15 lb/mmBTU or by 75%, would cost $73 million per year. Overall, the rule will have negligible impact on costs in comparison to the normal variations in other costs such as fuel and other operating and maintenance items.

By implementing the required emission reductions through a trading program, cost savings are estimated to be over 30% of what would otherwise be incurred. This level of savings has been realized in similar trading programs implemented by the EPA.

Some of the electric generating facilities and some of the remaining 5% of the nonutility sources which cannot cost effectively control emissions to comply with the rule will be able to comply by acquiring allowances from other sources on the open market, through mechanisms such as trade agreements, contracts and purchases. Allowances will be available both from electric generating companies with which many of these sources are owned or with which they do business and from the interstate market. It is anticipated that the market will provide for the least cost sources to control and minimize costs for all affected sources.

Since most of the affected sources already have the monitoring and reporting systems installed to comply with existing Federal requirements, only small changes will have to be made and reports will be consolidated with those existing requirements. On the whole, increased monitoring costs should be minimal for the majority of affected sources.

A few unmonitored sources may require additional reporting; however, the costs should also be small since the monitoring guidance allows for minimized and streamlined procedures which do not require new equipment. Common desktop personal computer-based spreadsheet software and data entry would be required. Since most sources already maintain this data, reformatting and submission is likely to be the most that is required for these sources.

Compliance Costs

It is expected that a number of Commonwealth facilities will be required to install emission controls to meet the emissions cap established by these final-form regulations. The open market approach which allows trading of emission reductions between sources will encourage the installation of the most cost-effective controls and trading of emission reductions between sources. This open market approach will significantly reduce compliance costs in comparison to a "command and control" approach. In addition to the control costs imposed, some of the sources covered by the program will be required to install additional monitoring equipment to accurately characterize NO_x emissions from the facility.

Compliance Assistance Plan

The Department plans to educate and assist the regulated community and the public with understanding the NO_x budget program.

Paperwork Requirements

This regulatory program will have paperwork impact on the Commonwealth and the regulated entities. In addition to monitoring, recordkeeping and reporting at the source level, the NO_x allowance tracking system and NO_x emissions tracking system require extensive multistate management.

G. *Pollution Prevention*

While this regulatory proposal does not directly include pollution prevention provisions, it may encourage some affected parties to switch from more polluting to less polluting fossil fuel sources.

H. *Sunset Review*

These final-form regulations will be reviewed in accordance with the sunset review schedule published by the Department to determine whether the regulations effectively fulfill the goals for which they were intended.

I. *Regulatory Review*

Under section 5(a) of the Regulatory Review Act (71 P. S. §§ 745.5(a)), on April 1, 1997, the Department submitted a copy of the amendments to IRRC and the Chairpersons of the Senate and House Environmental Resources and Energy Committees. In compliance with section 5(b.1) of the Regulatory Review Act, the Department also provided IRRC and the Committees with copies of the comments, as well as other documentation.

In preparing these final-form regulations, the Department has considered the comments received from IRRC and the public. These comments are addressed in the comment and response document and Section E of this Preamble. The Committees did not provide comments on the proposed rulemaking.

These final-form regulations were deemed approved by the House and Senate Environmental Resources and Energy Committee on October 7, 1997. IRRC met on October 9, 1997, and approved the final-form regulations in accordance with section 5(c) of the Regulatory Review Act.

J. *Findings of the Board*

The Board finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P. L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and regulations promulgated thereunder in 1 Pa. Code §§ 7.1 and 7.2.

(2) A public comment period was provided as required by law and all comments were considered.

(3) These final-form regulations do not enlarge the purpose of the proposal published at 27 Pa.B. 1829 (April 12, 1997).

(4) These final-form regulations are necessary and appropriate for administration and enforcement of the authorizing acts identified in Section C of this Preamble and are reasonably necessary to achieve and maintain the NAAQS for ozone.

K. *Order of the Board*

The Board, acting under the authorizing statutes, orders that:

(a) The regulations of the Department, 25 Pa. Code Chapters 121 and 123, are amended by amending § 121.1 and by adding §§ 123.101—123.120 and Appendix A to read as set forth in Annex A, with ellipses referring to the existing text of the regulations.

(b) The Chairperson of the Board shall submit this order and Annex A to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(c) The Chairperson shall submit this order and Annex A to IRRC and the Senate and House Environmental Resources and Energy Committees as required by the Regulatory Review Act.

(d) The Chairperson of the Board shall certify this order and Annex A and deposit them with the Legislative Reference Bureau as required by law.

(e) This order shall take effect immediately upon publication.

(*Editor's Note*: For a document amending § 121.1, amended in this document, see 27 Pa. B. 5601 (November 1, 1997.) Proposals to amend § 121.1, amended in this document remain outstanding at 27 Pa.B. 1822 (April 12, 1997), 27 Pa.B. 4325 (August 23, 1997) and 27 Pa.B. 4340 (August 23, 1997. The addition of § 123.121, included in the proposal at 27 Pa.B. 1829.)

(*Editor's Note*: For the text of the order of the Independent Regulatory Review Commission relating to this document, see 27 Pa.B. 5561 (October 25, 1997).)

Fiscal Note: Fiscal Note 7-314 remains valid for the final adoption of the subject regulations.

Annex A

TITLE 25. ENVIRONMENTAL PROTECTION

PART I. DEPARTMENT OF ENVIRONMENTAL PROTECTION

Subpart C. PROTECTION OF NATURAL RESOURCES

ARTICLE III. AIR RESOURCES

CHAPTER 121. GENERAL PROVISIONS

§ 121.1. Definitions.

The definitions in section 3 of the act (35 P. S. § 4003) apply to this article. In addition, the following words and terms, when used in this article, have the following meanings, unless the context clearly indicates otherwise:

* * * * *

Account—The place in the NO_x allowance tracking system where allowances are recorded including allowances held by a NO_x affected source.

Account number—The identification number given by the NO_x budget administrator to an account in which NO_x allowances are held in the NO_x allowance tracking system.

Acquiring account—The party in a NO_x allowance transfer who obtains NO_x allowances through purchase, trade, auction, gift or another lawful means.

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Compliance account—The place in the NO_x allowance tracking system where allowances are recorded and held by a NO_x affected source.

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Electric generating facility—For the purposes of NO_x allowance requirements, any fossil fuel fired combustion facility of 15 MW or greater electrical generating capacity.

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Fossil fuel—Natural gas, petroleum, coal or any form of solid, liquid or gaseous fuel derived from this material.

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Fossil fuel fired—The combustion of fossil fuel or, if in combination with any other fuel, fossil fuel comprises 51% or greater of the annual heat input on a Btu basis.

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General account—An account in the NATS that is not a compliance account.

* * * * *

Heat input—Heat derived from the combustion of fuel in a NO_x affected source. The term does not include the heat derived from preheated combustion air, recirculated flue gas or exhaust from another source or combination of sources.

* * * * *

Indirect heat exchange combustion unit—Combustion equipment in which the flame or products of combustion, or both, are separated from any contact with the principal material in the process by metallic or refractory walls, including, but not limited to, steam boilers, vaporizers, melting pots, heat exchangers, column reboilers, fractioning column feed preheaters, reactor feed preheaters, fuel-fired reactors such as steam hydrocarbon reformer heaters and pyrolisis heaters.

* * * * *

Maximum heat input capacity—The maximum steady state heat input under which a source may be operated as determined by its physical design and characteristics. Maximum heat input capacity is expressed in millions of British Thermal Units (MMBtu) per unit of time.

* * * * *

NATS-NO_x Allowance Tracking System—The computerized system used to track the number of NO_x allowances held and used by any person.

NETS-NO_x Emissions Tracking System—The computerized system used to track NO_x emissions from NO_x affected sources.

NO_x affected source—A fossil fuel fired indirect heat exchange combustion unit with a maximum rated heat input capacity of 250 MMBtu/hour or more and all fossil fuel fired electric generating facilities rated at 15 megawatts or greater or any other source that voluntarily opts to become a NO_x affected source.

NO_x allocation—Assignment by the Department of NO_x allowances to a NO_x affected source and recorded by the NO_x budget administrator to a NATS account.

NO_x allowance—The limited authorization to emit 1 ton of NO_x during a specified NO_x allowance control period.

NO_x allowance CEMS-NO_x Allowance Continuous Emissions Monitoring System—For the purposes of the NO_x allowance requirements, an emission monitoring system which continuously measures and records NO_x emissions.

NO_x allowance control period—The period beginning May 1 of each year and ending on September 30 of the same year, inclusive.

NO_x allowance curtailment—For the purposes of NO_x allowance requirements, a reduction in the hours of operation or in the rate of production.

NO_x allowance deduction—The withdrawal of NO_x allowances for permanent retirement by the NO_x budget administrator from a NATS account.

NO_x allowance transfer—The conveyance to another NATS account of one or more NO_x allowances from one person to another by whatever means, including, but not limited to, purchase, trade, auction or gift.

NO_x allowance transfer deadline—The deadline by which NO_x allowances may be submitted for recording in a NO_x affected source's compliance account for purposes of meeting NO_x allowance requirements.

NO_x budget—The total tons of NO_x emissions which may be released from NO_x affected sources as listed in Appendix A.

NO_x budget administrator—The person or agency designated by the Department as the NO_x budget administrator of the NATS and the NETS.

* * * * *

OTC MOU—Ozone Transport Commission Memorandum of Understanding—The memorandum of understanding signed by representatives of ten states and the District of Columbia as members of the Ozone Transport Commission on September 27, 1994.

* * * * *

Replacement source—A new source which is replacing a NO_x affected source where both sources are under common ownership located within this Commonwealth. The NO_x affected source shall be deactivated or permitted only as an emergency standby unit to the replacement source with operation limited to a maximum of 500 hours per year following commencement of operation of the replacement source.

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CHAPTER 123. STANDARDS FOR CONTAMINANTS

NO_x ALLOWANCE REQUIREMENTS

§ 123.101. Purpose.

Sections 123.102—123.120 and this section establish a NO_x budget and a NO_x allowance trading program for NO_x affected sources for the purpose of achieving the health based ozone ambient air quality standard.

§ 123.102. Source NO_x allowance requirements and NO_x allowance control period.

(a) The owner or operator or each NO_x affected source shall, by December 31 of each calendar year, hold a quantity of NO_x allowances meeting the requirements of § 123.110(a) (relating to source compliance requirements) in the source's current year NATS account that is equal to or greater than the total NO_x emitted from the source during that year's NO_x allowance control period.

(b) The initial NO_x allowance control period begins on May 1, 1999.

§ 123.103. General NO_x allowance provisions.

(a) NO_x allowances shall be allocated, transferred or used as whole NO_x allowances. To determine the number of whole NO_x allowances, the number of NO_x allowances shall be rounded down for decimals less than 0.50 and rounded up for decimals of 0.50 or greater.

(b) A NO_x allowance does not constitute a security or other form of property.

(c) Allowances may not be used to meet the requirements of this subchapter prior to the year for which they are allocated.

(d) For the purposes of account reconciliation, NO_x allowances allocated for the NO_x allowance control period shall be deducted first, and remaining allowances if not otherwise designated by the source shall be deducted on a first-in, first-out basis.

(e) NO_x allowances may only be used to comply with §§ 123.101, 123.102, 123.104—123.120 and this section (relating to NO_x allowance requirements).

§ 123.104. Source authorized account representative requirements.

(a) The owner or operator of a NO_x affected source shall designate for each source account, one authorized account representative and one alternate. Initial designations shall be submitted to the Department by December 1, 1997. An authorized account representative may be replaced or, for a new NO_x affected source, designated with the submittal of a new "Account Certificate of Representation."

(b) The "Account Certificate of Representation" shall be signed by the authorized account representative for the NO_x affected source and contain, at a minimum, the following:

(1) Identification of the NO_x affected source by plant name, state and fossil fired indirect heat transfer combustion unit number for which the certification of representation is submitted.

(2) The name, address, telephone and facsimile number of the authorized account representative and the alternate.

(3) A list of owners and operators of the NO_x affected source.

(4) The verbatim statement, "I certify that I, ________ , was selected as the Authorized Account Representative (name) by an agreement binding on the owners and operators of the NO_x affected source legally designated as ________ ." (name of facility)

(c) The alternate authorized account representative shall have the same authority as the authorized account representative. Correspondence from the NO_x budget administrator shall be directed to the authorized account representative.

(d) Only an authorized account representative or the designated alternate may request transfers of NO_x allowances in a NATS account. The authorized account representative shall be responsible for all transactions and reports submitted to the NATS.

(e) Authorized account representative designation or changes become effective upon the logged date of receipt of a complete application by the NO_x budget administrator from the Department. The NO_x budget administrator will acknowledge receipt and the effective date of the changes by written correspondence to the authorized account representative.

§ 123.105. NATS provisions.

(a) The NATS account records shall constitute a NO_x affected source's NO_x allowance holdings.

(b) The transfer, use and deduction of NO_x allowances become effective only after entry in the tracking system account records.

(c) Any person may hold an account in the NATS.

§ 123.106. NO_x allowance transfer protocol.

(a) NO_x allowances may be transferred at any time between January 31 and December 31 in accordance with § 123.107 (relating to NO_x allowance transfer procedures).

(b) NO_x allowances shall be held by the originating account at the time of the transfer request.

(c) A transfer request shall be filed jointly with the NO_x budget administrator and the Department by the person named as the authorized account representative for the originating account.

(d) The transfer is effective as of the date the NO_x budget administrator posts the transfer of the allowances on the NATS.

§ 123.107. NO_x allowance transfer procedures.

NO_x allowances may be transferred under the following conditions:

(1) The transfer request shall be documented on a form, or electronic media, approved by the Department. The following information, at a minimum, shall be provided:

(i) The account number identifying both the originating account and the acquiring account.

(ii) The name and address associated with the owners of the originating account and the acquiring account.

(iii) The identification of the serial numbers for each NO_x allowance being transferred.

(2) The transfer request shall be authorized and certified by the authorized account representative for the originating account. To be considered correctly submitted, the request for transfer shall include the following statement of certification:

> "I am authorized to make this submission on behalf of the owners and operators of the NO_x affected source and I hereby certify under the penalty provisions contained in the Air Pollution Control Act, that I have personally examined the foregoing and am familiar with the information contained in this document, and all attachments, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment."

The authorized account representative for the originating account shall provide a copy of the transfer request to each owner or operator of the NO_x affected source.

§ 123.108. Source emissions monitoring requirements.

The owner and operator of each NO_x affected source shall comply with the following requirements:

(1) NO_x emissions from each NO_x affected source shall be monitored as specified by this section and in accordance with the procedures contained in the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(2) The owner or operator of each NO_x affected source shall submit to the Department and the NO_x budget administrator a monitoring plan in accordance with the procedures outlined in the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(3) New and existing unit emission monitoring systems, as required and specified by this section, shall be installed and be operational and shall have met all of the certification testing requirements in accordance with the procedures and deadlines specified in the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program" in a manner consistent with Chapter 139 (relating to sampling and testing).

(4) Monitoring systems are subject to initial performance testing and periodic calibration, accuracy testing and quality assurance/quality control testing as specified in the document titled "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program." Notwithstanding this provision, Non-Part 75 Sources which have Department approved NO_x CEMS reporting in accordance with § 139.101 (relating to gen-

eral requirements) in units of pounds of NO_x per hour shall complete the periodic self-audits listed in the quality assurance section of § 139.102(3) (relating to references) at least annually and no sooner than 6 months following the previous periodic self-audit. If practicable, the audit shall be conducted between April 1 and May 31.

(5) During a period when valid data is not being recorded by devices approved for use to demonstrate compliance with this subchapter, missing or invalid data shall be replaced with representative default data in accordance with 40 CFR Part 75 (relating to continuous emission monitoring) and the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program." Notwithstanding this provision, Non-Part 75 Sources which have Department approved NO_x CEMS reporting in accordance with § 139.101 in units of pounds of NO_x per hour shall report this data to the NETS and shall continue report submissions as required under Chapter 139 to the Department.

(6) Sources subject to 40 CFR Part 75 shall demonstrate compliance with this section with a certified Part 75 monitoring system.

(i) If the source has a flow monitor certified under Part 75, NO_x in pounds per hour shall be determined using the Part 75 NO_x CEMS and the flow monitor. The NO_x emission rate in pounds per million Btu shall be determined using the procedure in 40 CFR Part 75 Appendix F, Section 3 (relating to procedures for NO_x emission rate). The hourly heat input shall be determined by using the procedures in 40 CFR Part 75 Appendix F, Section 5 (relating to procedures for heat input). NO_x in pounds per hour shall be determined by multiplying the NO_x per million Btu by the Btus per hour.

(ii) If a Part 75 source does not have a certified flow monitor, but does have a certified NO_x CEMS, NO_x emissions in pounds per hour emissions shall be determined by using the NO_x CEMS to determine the NO_x emission rate in pounds per million Btu and the heat input shall be determined by using the procedures in 40 CFR Part 75 Appendix D (relating to optional SO_2 emissions data protocol for gas-fired and oil-fired units). NO_x in pounds per hour shall be determined by multiplying the NO_x per million Btu and Btus per hour.

(iii) If the owner or operator of a source uses the procedures in 40 CFR Part 75, Appendix E (relating to optional NO_x emissions estimation protocol for gas-fired peaking units and oil-fired peaking units) to determine the NO_x emission rate, NO_x emissions in pounds per hour shall be determined by multiplying the NO_x emission rate determined by using the Appendix E procedures times the heat input determined using the procedures in 40 CFR Part 75, Appendix D.

(iv) If the owner or operator of a source uses the procedures in 40 CFR Part 75, Subpart E (relating to alternative monitoring systems) to determine NO_x emission rate, NO_x emissions in pounds per hour shall be determined using the alternative monitoring method approved under 40 CFR Part 75 Subpart E and the procedures contained in the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(v) If the source emits to common or multiple stacks, or both, the source shall monitor emissions according to the procedures contained in the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(7) Sources not subject to 40 CFR Part 75 and not meeting the requirements of paragraph (11) shall meet the monitoring requirements of this section by:

(i) Preparing and obtaining approval of a monitoring plan as specified in the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(ii) Determining NO_x emission rate and heat input using a methodology specified in paragraphs (8) and (9) respectively or determining NO_x concentration and flow using a methodology specified in paragraphs (8) and (9) respectively.

(iii) Calculating NO_x emissions in pounds per hour using the procedure described in paragraph (10).

(8) The owner or operator of a NO_x affected source which is not subject to 40 CFR Part 75, may implement an alternative emission rate monitoring method. The NO_x emission rate in pounds per million Btu or NO_x concentration in ppm shall be determined using one of the following methods:

(i) The owner or operator of a NO_x affected source that has a maximum rated heat input capacity of 250 MMBtu/hr or greater which is not a peaking unit as defined in 40 CFR 72.2 (relating to definitions), which combusts any solid fuel or is required to or has installed a NO_x continuous emissions monitoring system (NO_x CEMS) for the purposes of meeting either the requirements of 40 CFR Part 60 (relating to standards of performance for new stationary sources) or another Department or Federal requirement, shall use that NO_x CEMS to meet the requirements of this section. If the owner or operator of the unit monitors flow according to paragraph (9), the owner or operator may use the NO_x CEMS to measure NO_x in ppm, otherwise the NO_x CEMS shall be used to measure the emission rate in lb/MMBtu. The owner or operator shall install, certify, operate and maintain this monitor in accordance with the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program." When a NO_x CEMS cannot be used to report data for this program because it does not meet the requirements of the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program," missing data shall be substituted using the procedures in that document. In addition, the NO_x CEMS shall meet the initial certification requirements contained in the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(ii) The owner or operator of a source that is not required to have a NO_x CEMS, may request approval from the Department to use any of the following appropriate methodologies to determine the NO_x emission rate:

(A) Boilers or turbines may use the procedures contained in 40 CFR Part 75 Appendix E to measure NO_x emission rate in pounds/MMBtu, consistent with the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(B) Owners and operators of combustion turbines that are subject to this section and §§ 123.101—123.107 and 123.109—123.120 (relating to NO_x allowance requirements) may also meet the monitoring requirements of this section and §§ 123.101—123.107 and 123.109—123.120 by using default emission factors to determine NO_x emissions in pounds per hour as follows:

(I) For gas-fired turbines, the default emission factor is 0.7 pounds NO_x per MMBtu.

(II) For oil-fired turbines, the default factor is 1.2 pounds NO_x per MMBtu.

(III) Owners and operators of gas turbines or oil-fired turbines may perform testing, consistent with "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program," to determine unit specific maximum potential NO_x emission rates.

(C) Owners and operators of boilers that are subject to this section and §§ 123.101—123.107 and 123.109—123.120 may meet the monitoring requirements of this section and §§ 123.101—123.107 and 123.109—123.120 by using a default emission factor of 2.0 pounds per MMBtu if they burn oil and 1.5 lb/MMBtu if they burn natural gas to determine NO_x emissions in pounds per hour, or may perform testing consistent with the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program," to determine a unit specific maximum potential emission rate.

(9) The owner or operator of a source which is not subject to 40 CFR Part 75, and not meeting the requirements of paragraph (11), shall determine heat input in MMBtu or flow in standard cubic feet per hour using one of the following methods:

(i) The owner or operator of a source may install and operate a flow monitor according to 40 CFR Part 75.

(A) The owner or operator may either use the flow CEMS to monitor stack flow in standard cubic feet per hour and a NO_x CEMS to monitor NO_x in ppm.

(B) In the alternative, the owner or operator may use the flow CEMS and a diluent CEMS to determine heat input in MMBtu and a NO_x CEMS to monitor NO_x in lbs/MMBtu.

(ii) The owner or operator of a source that does not have a flow CEMS may request approval from the Department to use any of the following methodologies to determine their heat input rate:

(A) The owner or operator of a source may determine heat input using a flow monitor and a diluent monitor meeting 40 CFR Part 75 and the procedures in 40 CFR Part 75, Appendix F Section 5.

(B) The owner or operator of a source that combusts only oil or natural gas may determine heat input using a fuel flow monitor meeting 40 CFR Part 75 Appendix D and the procedures of 40 CFR Part 75, Appendix F Section 5.

(C) The owner or operator of a source that combusts only oil or natural gas which uses a unit specific or generic default NO_x emission rate, may determine heat input by measuring the fuel usage for a specified frequency of longer than an hour. This fuel usage shall then be reported on an hourly basis by apportioning the fuel based on electrical load in accordance with the following formula:

$$\text{Hourly fuel usage} = \frac{\text{Hourly electrical load} \times \text{total fuel usage}}{\text{Total electrical load}}$$

(D) The owner or operator of a source that combusts any fuel other than oil or natural gas, may request permission from the Department to use an alternative method of determining heat input. Alternative methods include:

(I) Conducting fuel sampling and analysis and monitoring fuel usage.

(II) Using boiler efficiency curves and other monitored information such as boiler steam output.

(III) Other methods approved by the Department and which meet the requirements in the "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(E) Alternative methods for determining heat input are subject to both initial and periodic relative accuracy, and quality assurance testing as prescribed by "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(10) If the owner or operator determines NO_x emission rate in pounds per million Btu in accordance with paragraph (6)(iii) and heat input rate in MMBtu per hour in accordance with paragraph (7), the two values shall be multiplied to result in NO_x emissions in pounds per hour. If the owner or operator determines NO_x emissions in ppm and flow in standard cubic feet per hour, the procedures in "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program" may be used to determine NO_x emissions of this rule in pounds per hour. This value shall be reported to the NETS.

(11) Non-Part 75 sources which have Department approved NO_x CEMS reporting in accordance with § 139.101 in units of pounds of NO_x per hour may meet the monitoring requirements of paragraph (7); or shall comply with the following:

(i) Calibration standards used shall be in accordance with both 40 CFR Part 75, Appendix A, Section 5.2 (relating to concentrations) and with § 139.102(3).

(ii) Testing listed in 40 CFR Part 75, Appendix A, Section 6.4 (relating to cycle time/response time test) not already conducted as part of the response time testing in § 139.102(3) shall be conducted.

(iii) Bias testing of the relative accuracy test data in accordance with 40 CFR Part 75, Appendix A, Section 6.5 (relating to relative accuracy and bias tests) shall be conducted. Data from previously conducted relative accuracy testing may be used to meet this requirement.

(iv) Adjustment of data due to failure of bias test (in accordance with 40 CFR Part 75, Appendix A, Section 7.6.5 (relating to bias adjustment) and Appendix B, Section 2.3.3 (relating to bias adjustment factor)) or relative accuracy greater than 10% but less than or equal to 20% (by multiplying the NO_x emissions rate by 1.1), or both, shall be conducted only for reporting to the NO_x budget administrator for purposes of this section.

(v) A Data Acquisition Handling System verification demonstrating that both the missing data procedures and formulas as applicable to this section shall be conducted.

§ 123.109. Source emissions reporting requirements.

(a) The authorized account representative for each NO_x affected source shall submit to the NO_x budget administrator, electronically in a format which meets the requirements of the EPA's Electronic Data Reporting convention, emissions and operations information for each calendar quarter of each year in accordance with the document titled, "Guidance for Implementation of Emission Monitoring Requirements for the NO_x Budget Program."

(b) Upon permanent shutdown, NO_x affected sources may be exempted from this section after receiving written Department approval of a request filed by the authorized account representative for the NO_x affected source which identifies the source and date of shutdown.

§ 123.110. Source compliance requirements.

(a) Each year from November 1 through December 31, inclusive, the authorized account representative shall request the NO_x budget administrator to deduct, consistent with § 123.107 (relating to NO_x allowance transfer procedures) a designated amount of NO_x allowances by serial number, from the NO_x affected source's compliance account in an amount equivalent to the NO_x emitted from the NO_x affected source during that year's NO_x allowance control period in accordance with the following:

(1) Allowances allocated for the current NO_x control period may be used without restriction.

(2) Allowances allocated for future NO_x control periods may not be used.

(3) NO_x allowances which were allocated for any preceding NO_x allowance control period which were not used (banked) may be used in the current control period even if this may result in an unlimited exceedance of the NO_x budget. Banked allowances shall be deducted against emissions in accordance with a ratio of NO_x allowances to emissions as specified by the NO_x budget administrator as follows:

(i) If the total NO_x allowances remaining in the NATS for all sources for preceding NO_x allowance control periods are less than or equal to 10% of the total NO_x allowances allocated for that NO_x allowance control period, the ratio is 1:1.

(ii) If the total NO_x allowances remaining in the NATS for all sources for preceding NO_x allowance control periods are greater than 10% of the NO_x allowances allocated for that NO_x allowance control period, the ratio is 2:1 for the portion of banked allowances used for compliance from an account which are in excess of the amount calculated by multiplying the total allowances banked in the account times the PFC (progressive flow control).

where

$$PFC = \frac{0.1 \times NO_x \text{ allowances allocated for the control period}}{\text{total amount of banked allowances in the NATS}}$$

(b) If, by the December 31 compliance deadline, the authorized account representative either makes no NO_x allowance deduction request, or a NO_x allowance deduction request insufficient to meet the requirements of subsection (a), the NO_x budget administrator may deduct the necessary number of NO_x allowances from the NO_x affected source's compliance account. The NO_x budget administrator shall provide written notice to the authorized account representative that NO_x allowances were deducted from the source's account. If the necessary number of NO_x allowances is available, the source will be in compliance after the NO_x allowance deduction is completed. If there is an insufficient number of NO_x allowances available for NO_x allowance deduction, § 123.111 (relating to failure to meet source compliance requirements) applies.

(c) For each NO_x allowance control period, the authorized account representative for the NO_x affected source shall submit an annual compliance certification to the Department.

(d) The compliance certification shall be submitted no later than the NO_x allowance transfer deadline (December 31) of each year.

(e) The compliance certification shall contain, at a minimum, the following:

(1) An identification of the NO_x affected source, including the name, address, the name of the authorized account representative and the NATS account number.

(2) A statement indicating whether or not emissions data has been submitted to the NETS in accordance with § 123.108 (relating to source emissions monitoring requirements).

(3) A statement indicating whether or not the NO_x affected source held sufficient NO_x allowances, as determined in subsection (a), in its compliance account for the NO_x allowance control period, as of the NO_x allowance transfer deadline, to equal or exceed the NO_x affected source's actual emissions and the emissions reported to the NETS for the NO_x allowance control period.

(4) A statement indicating whether or not the monitoring plan which governs the NO_x affected source was followed when monitoring the actual operation of the NO_x affected source.

(5) A statement indicating that all emissions from the NO_x affected source were accounted for, either through the applicable monitoring or through application of the appropriate missing data procedures.

(6) A statement indicating whether there were any changes in the method of operation of the NO_x affected source or the method of monitoring of the NO_x affected source during the current year.

(f) The Department may verify compliance by whatever means necessary, including one or more of the following:

(1) Inspection of facility operating records.

(2) Obtaining information on NO_x allowance deduction and transfers from the NATS.

(3) Obtaining information on emissions from the NETS.

(4) Testing emission monitoring devices.

(5) Requiring the NO_x affected source to conduct emissions testing in accordance with Chapter 139 (relating to sampling and testing).

§ 123.111. Failure to meet source compliance requirements.

(a) Failure by the NO_x affected source to hold in its compliance account, for a NO_x allowance control period, as of the NO_x allowance transfer deadline, sufficient NO_x allowances equal to or exceeding actual emissions for the NO_x allowance control period as specified under § 123.102 (relating to source allowance requirements and NO_x allowance control period) shall result in NO_x allowance deduction from the NO_x affected source's compliance account at the rate of 3 NO_x allowances for every 1 ton of excess emissions. If sufficient allowances meeting the requirements of § 123.110(a) (relating to source compliance requirements) are not available, the source shall provide other sufficient allowances which shall be deducted prior to the beginning of the next NO_x allowance control period, otherwise the source may not operate during subsequent control periods.

(b) In addition to the NO_x allowance deduction required by subsection (a), the Department may enforce the provisions of this section and §§ 123.101—123.110 and 123.112—123.120 under the act and the Clean Air Act.

(1) For purposes of determining the number of days of violation, any excess emissions for the NO_x allowance control period shall presume that each day in the NO_x allowance control period constitutes a day in violation (153 days) unless the NO_x affected source can demonstrate, to the satisfaction of the Department, that a lesser number of days should be considered.

(2) Each ton of excess emissions is a separate violation.

§ 123.112. Source operating permit provision requirements.

The operating permit required under Chapter 127 (relating to construction, modification, reactivation and operations of sources) shall include a condition requiring compliance with §§ 123.101—123.111, 123.113—123.120 and this section (relating to NO_x allowance requirements). The NATS compliance account number and the authorized account representative shall be listed on the permit.

§ 123.113. Source recordkeeping requirements.

The owner or operator of a NO_x affected source shall maintain for each NO_x affected source and for 5 years, or any other period consistent with the terms of the NO_x affected source's operating permit, the measurements, data, reports and other information required by §§ 123.101—123.112, 123.114—123.120 and this section.

§ 123.114. General NO_x allocation provisions.

(a) NO_x allocations to NO_x affected sources may only be made by the Department.

(b) Except as provided in § 123.116 (relating to source opt-in provisions), for NO_x affected sources identified in Appendix A which shutdown or curtail operations, the source account will continue to receive NO_x allowances for each NO_x allowance control period.

§ 123.115. Initial NO_x allowance NO_x allocations.

(a) The sources contained in Appendix A are subject to the requirements of §§ 123.101—123.114, 123.116—123.120 and this section. These sources are allocated NO_x allowances for the 1999—2002 NO_x allowance control periods as listed in Appendix A. Except as provided in § 123.120 (relating to audit), if no allocation is specified for the NO_x allowance control periods beyond 2002, the current allocations continue indefinitely.

(b) The Washington Power Company and Colver Power Project sources identified in Appendix A shall receive the allocation identified in Appendix A upon operation of the source.

(c) The Department may allocate allowances to Duquesne Light Company's Phillips and Brunot Island facilities. The allowances allocated to these facilities are limited as follows:

(1) The facility shall be fully operational.

(2) The allowances allocated to the facility may only be used by the baseline sources located at that facility, and may not be banked or transferred.

(3) The allocation to Brunot Island source identification numbers 001—012 may not exceed an aggregate 246 allowances for the period May 1—September 30.

(4) The allocation to Phillips Station boilers 1—6 may not exceed an aggregate 1,686 allowances for the period May 1—September 30.

§ 123.116. Source opt-in provisions.

(a) A person who owns, operates, leases or controls a non-NO_x affected source located in this Commonwealth may apply to the Department to opt-in that source to become a NO_x affected source. For replacement sources, all sources to which production may be shifted to shall be opted-in together.

(b) A source which began operations without emission reduction credits transferred from a NO_x affected source may become a NO_x affected source under the following conditions:

(1) Submission of an opt-in application to the Department, including:

(i) Documentation of baseline NO_x allowance control period emissions which shall be the average of the actual emissions for the preceding two consecutive NO_x allowance control periods. The Department may approve selection of an alternative two consecutive NO_x allowance control periods within the 5 years preceding the opt-in application if the preceding two control periods are not representative of normal operations. The baseline may not exceed applicable emission limits.

(ii) Evidence that the requirements of §§ 123.101—123.115, 123.117—123.120 and this section (relating to NO_x allowance requirements) can be complied with, including, submission of an emission monitoring plan, designation of an authorized account representative, and that the source is not on the compliance docket established under section 7.1 of the act (35 P. S. § 4005).

(2) Submission of NO_x allowances established under paragraph (1)(i) or subsection (c) by the Department to the NO_x budget administrator.

(c) A source which began operations with emission reduction credits from a NO_x affected source may become a NO_x affected source by complying with subsection (b)(1). To operate the source, NO_x allowances shall be acquired by the owner or operator from those available in the NATS.

(d) Opt-in sources which opted-in under subsection (b) and which shutdown or curtail operations during any NO_x allowance control period within the 5-calendar years after opting-in shall, prior to January 31 following the shutdown or curtailment, surrender to the Department NO_x allowances for the current NO_x allowance control period equivalent to the difference resulting from the reduction in utilization from the source's baseline operations as established in subsection (b)(1)(i) between the NO_x allowance control period allowance allocation and the emissions reported in accordance with § 123.109 (relating to source emissions reporting requirements). NO_x allocations for future NO_x allocation control periods shall also be surrendered. NO_x allowances which were allocated for any preceding NO_x allowance control period which were not used (banked) may not be surrendered. Surrendered NO_x allowances shall be retired from the NATS and NO_x budget except that upon request by the source owner or operator, the Department may reallocate the NO_x allowances to a qualifying replacement source.

(e) Opt-in sources which remain in operation for 5-calendar years from the date of opt-in shall have a new baseline and allowance allocation set in accordance with the procedure in subsection (b)(1)(i). This baseline may not exceed the opt-in baseline. Thereafter, the source is not subject to this section.

(f) Once electing to opt-in, a source may not revert to a non-NO_x affected source unless it is shut down.

§ 123.117. New NO_x affected source provisions.

(a) NO_x allowances may not be created for new NO_x affected sources. New NO_x affected sources are sources which are not listed in § 123.115 (relating to initial NO_x allowance NO_x allocations). The owner or operator of a new NO_x affected source shall establish a compliance account prior to the commencement of operations and is responsible to acquire any required NO_x allowances from those available in the NATS.

(b) Newly discovered NO_x affected sources not included in Appendix A which operated at any time between May 1 and September 30, 1990, shall comply with §§ 123.101—123.116, 123.118—123.120 and this section (relating to NO_x allowance requirements) within 1-calendar year from the date of discovery. For those sources which notify the Department by April 1, 1998, the Department will petition the OTC to include the emissions in the NO_x MOU Budget and provide NO_x allowances to the source using the historical May 1 to September 30, 1990, emissions reduced as specified in § 123.119(a)(4)(ii) (relating to bonus NO_x allowance awards).

§ 123.118. Emission reduction credit provisions.

(a) NO_x affected sources may create, transfer and use emission reduction credits in accordance with Chapter 127 (relating to construction, modification, reactivation and operation of sources) and this section. ERCs may not be used to satisfy NO_x allowance requirements.

(b) Emission reductions made through overcontrol, curtailment or shutdown for which allowances are banked are not surplus and may not be used to create ERCs.

(c) A NO_x affected source may transfer NO_x ERCs to an NO_x affected source if the new or modified NO_x affected source's ozone season (May 1—September 30) allowable emissions do not exceed the ozone season portion of the baseline emissions which were used to generate the NO_x ERCs.

(d) A NO_x affected source may transfer NO_x ERCs to a non-NO_x affected source under the following conditions:

(1) The non-NO_x affected source's ozone season (May 1—September 30) allowable emissions may not exceed the ozone season portion of the baseline emissions which were used to generate the NO_x ERCs.

(2) The NATS account for NO_x affected sources which generated ERCs transferred to non-NO_x affected sources, including prior to the date of publication in the *Pennsylvania Bulletin*, shall have a corresponding number of allowances retired that reflect the transfer of emissions regulated under §§ 123.101—123.117, 123.119—123.120 and this section (relating to NO_x allowance requirements) to the NO_x nonaffected sources. The amount of annual NO_x allowances deducted shall be equivalent to that portion of the nonaffected source's NO_x control period allowable emissions which were provided for by the NO_x ERCs from the affected source.

(3) Allocations for NO_x allowance control periods following 2002 to the NO_x ERC generating source may not include the allowances identified in paragraph (2).

§ 123.119. Bonus NO_x allowance awards.

(a) The Department will, upon receipt of a complete application by November 1, 1998, award a NO_x affected source with bonus NO_x allowances for certain creditable emission reductions made during the 1997 and 1998 ozone seasons (May 1—September 30) under the following conditions:

(1) Creditable reductions shall be in excess of the OTC MOU reduction requirements and any applicable emission limits including RACT and maximum achievable control technology.

(2) Bonus allowances shall be calculated separately for the 1997 and 1998 ozone seasons (May 1—September 30).

(3) The actual average ozone season (May 1—September 30) heat input used to calculate the emission reduction may not exceed the average 1995 and 1996 ozone season actual heat input, or if the Department finds that it is more representative of normal operations, the average ozone season (May 1—September 30) actual heat input which occurred during another consecutive 2 years between and including 1991 and 1995.

(4) Bonus NO_x allowances shall be calculated by multiplying the actual 1997 or 1998, as applicable, average ozone season (May 1—September 30) heat input, times the difference between the following:

(i) The after-control emission rate calculated using the average rate occurring during the 1997 or 1998 NO_x allowance control.

(ii) The lower of the source's applicable emission rate for NO_x expressed in pounds of NO_x per MMBtu, or the baseline emission rate established in Appendix A after applying the following reduction, as applicable. The reduction for sources located in the outer zone is 55% or 0.2 lbs/MMBtu whichever is less stringent, and for sources located in the inner zone, 65%, or 0.2 lbs/MMBtu whichever is less stringent. The inner zone includes Berks, Bucks, Chester, Delaware, Montgomery and Philadelphia counties, and the outer zone includes the remaining counties within this Commonwealth.

(5) Applications shall include the information necessary to determine that the reductions meet the requirements of this section.

(b) On or before May 1, 1999, the Department will publish a report in the *Pennsylvania Bulletin* which documents the number of bonus NO_x allowances awarded.

§ 123.120. Audit.

(a) The Department will complete an audit of the program established by §§ 123.101—123.119 and this section (relating to NO_x allowance requirements) prior to May 1, 2002, and at a minimum every 3 years thereafter. The audit shall include the following:

(1) The resulting geographic distribution of emissions as well as the hourly, daily and running average emission totals shall be examined in the context of ozone control requirements. This analysis shall be used in making a determination as to whether the zonal, seasonal and interseasonal trading and banking provisions of the rule require modification to ensure the reductions are as effective as daily emission limits on all sources would be at reducing ozone.

(2) Confirmation of emissions reporting accuracy through validation of NO_x allowance CEMS and data acquisition systems at the NO_x affected source.

(3) If emissions in excess of the NO_x allowances allocated occurred in any NO_x allowance control period, as a result of banking provisions, a determination whether or not the NO_x allowance banking provisions require modification or deletion.

(4) NO_x allowance banking privileges will be examined to determine whether they adversely influenced market availability and price of NO_x allowances or created unfair competitive advantages and if so, recommend amendments to rectify these problems.

(5) An assessment of whether the program is providing the level of emission reductions included in the current SIP.

(b) In addition to the Department audit, the Department may seek a third party audit of the program. The third party audit can be implemented on a state by state basis or can be performed on a region-wide basis under the supervision of the Ozone Transport Commission.

(c) The Department will propose regulation revisions consistent with the audit results within 6 months of the completion of the audit.

Appendix A

County	*Facility*	*Combustion Source Name*	*Point ID*	*Allowance*	*Baseline NO_x lb/MMBtu*	*Baseline MMBtu*
Adams	Met Edison Hamilton		031	4	0.59	18,716
Adams	Met Edison Ortanna		031	3	0.59	13,130
Adams	Metropolitan Edison Company	G. E. N Frame Turbine #1	031	17	0.45	89,908
Adams	Metropolitan Edison Company	G. E. N Frame Turbine #2	032	6	0.45	29,243
Adams	Metropolitan Edison Company	G. E. N Frame Turbine #3	033	14	0.45	74,249
Allegheny	Duquesne Light Company, Cheswick	Boiler	001	2,114	0.61	15,025,580
Armstrong	Penelec—Keystone	Boiler No. 1	031	4,342	0.80	25,149,236
Armstrong	Penelec—Keystone	Boiler No. 2	032	3,446	0.79	22,657,898
Armstrong	West Penn Power Co.	Foster Wheeler	031	1,140	0.95	5,355,101
Armstrong	West Penn Power Co.	Foster Wheeler	032	1,066	1.02	5,007,467
Beaver	AES Beaver Valley Partners, Inc.	Babcock and Wilcox	032	302	0.83	1,747,462
Beaver	AES Beaver Valley Partners, Inc.	Babcock and Wilcox	033	247	0.83	1,431,342
Beaver	AES Beaver Valley Partners, Inc.	Babcock and Wilcox	034	286	0.83	1,655,847
Beaver	AES Beaver Valley Partners, Inc.	Babcock and Wilcox	035	154	0.81	683,951
Beaver	Penn Power Co.—Bruce Mansfield	Boiler Unit 1	031	2,993	0.90	16,618,929
Beaver	Penn Power Co.—Bruce Mansfield	Foster Wheeler Unit No. 2	032	3,866	0.90	21,464,786
Beaver	Penn Power Co.—Bruce Mansfield	Foster Wheeler Unit 3	033	3,504	0.70	19,455,843
Beaver	Zinc Corporation Of America	Coal Boiler 1	034	241	0.80	1,380,627
Beaver	Zinc Corporation Of America	Coal Boiler 2	035	204	0.80	1,168,776
Berks	Metropolitan Edison Co.—Titus	Unit 1	031	202	0.65	1,836,587
Berks	Metropolitan Edison Co.—Titus	Unit 2	032	186	0.68	1,632,072
Berks	Metropolitan Edison Co.—Titus	Unit 3	033	201	0.66	1,805,003
Berks	Metropolitan Edison Co.—Titus	No. 4 Combustion Turbine	034	2	0.44	20,010
Berks	Metropolitan Edison Co.—Titus	No. 5 Combustion Turbine	035	2	0.44	15,484
Blair	Penelec—Williamsburg	No. 11 Boiler—Rily	031	38	0.87	200,874
Bucks	PECO Energy—Croyden	Croyden—Turbine #11	031	11	0.70	42,451
Bucks	PECO Energy—Croyden	Croyden—Turbine #12	032	7	0.70	26,382
Bucks	PECO Energy—Croyden	Croyden—Turbine #21	033	44	0.70	175,640
Bucks	PECO Energy—Croyden	Croyden—Turbine #22	034	20	0.70	81,649
Bucks	PECO Energy—Croyden	Croyden—Turbine #31	035	11	0.70	42,534
Bucks	PECO Energy—Croyden	Croyden—Turbine #32	036	14	0.70	54,905
Bucks	PECO Energy—Croyden	Croyden—Turbine #41	037	8	0.70	30,191
Bucks	PECO Energy—Croyden	Croyden—Turbine #42	038	38	0.70	152,094
Bucks	United States Steel Corp., The	Power House Boiler No. 3	043	63	0.26	655,625
Bucks	United States Steel Corp., The	Power House Boiler No. 4	044	14	0.27	147,330

County	*Facility*	*Combustion Source Name*	*Point ID*	*Allowance*	*Baseline NO_x lb/MMBtu*	*Baseline MMBtu*
Bucks	United States Steel Corp., The	Power House Boiler No. 5	045	73	0.26	756,980
Bucks	United States Steel Corp., The	Power House Boiler No. 6	046	84	0.26	871,810
Cambria	Cambria CoGen Company	A Boiler	031	200	0.24	2,003,177
Cambria	Cambria CoGen Company	B Boiler	032	212	0.23	2,116,233
Cambria	Colver Power Project			411	0.20	4,112,640
Cambria	Ebensburg Power Company	CFB Boiler		206	0.08	2,058,858
Carbon	Panther Creek Energy Facility	Boiler 1		119	0.12	1,592,491
Carbon	Panther Creek Energy Facility	Boiler 2		117	0.12	1,555,673
Chester	PECO Energy—Cromby	Boiler No 1	031	247	0.82	1,660,770
Chester	PECO Energy—Cromby	Boiler No 2	032	187	0.28	1,257,120
Clarion	Piney Creek Project	CFB Boiler		122	0.18	1,217,989
Clearfield	Penelec—Shawville	Babcock Wilcox Boiler	031	981	1.22	3,737,976
Clearfield	Penelec—Shawville	Babcock Wilcox Boiler	032	947	1.21	3,624,416
Clearfield	Penelec—Shawville	Combustion Engineering	033	852	0.86	4,558,942
Clearfield	Penelec-Shawville	Combustion Engineering	034	693	0.87	3,697,889
Clinton	International Paper Co.	1 Riley Stoker Vo-Sp	033	145	0.55	1,220,703
Clinton	International Paper Co.	2 Riley Stoker Vo-Sp	034	145	0.55	1,218,878
Clinton	PP&L—Lock Hanve	CT 1			0.49	14,818
Columbia	Penelec—Benton		002	1	2.33	2,661
Columbia	Penelec—Benton		003	1	2.93	2,330
Cumberland	Metropolitan Edison Company	G.E. N Frame Turbine	031	9	0.45	46,665
Cumberland	Metropolitan Edison Company	G.E. N Frame Turbine #1	032	11	0.45	55,480
Cumberland	PP&L-West Shore	*CT 1*		3	0.49	12,402
Cumberland	PP&L-West Shore	*CT 2*		3	0.49	13,231
Dauphin	PP&L-Harrisburg	*CT 1*		4	0.49	16,282
Dauphin	PP&L-Harrisburg	*CT 2*		4	0.49	15,884
Dauphin	PP&L-Harrisburg	*CT 3*		4	0.49	15,446
Dauphin	PP&L-Harrisburg	*CT 4*		4	0.49	15,386
Delaware	BP Oil, Inc.	7 Boiler	032	35	0.37	331,917
Delaware	BP Oil, Inc.	8 Boiler	033	56	0.48	535,337
Delaware	BP Oil, Inc.		038	187	0.55	1,789,455
Delaware	PECO Energy-Eddystone	No. 1 Boiler	031	663	0.54	5,571,014
Delaware	PECO Energy-Eddystone	No. 2 Boiler	032	432	0.55	3,629,294
Delaware	PECO Energy-Eddystone	No. 3 Boiler	033	257	0.28	2,153,713
Delaware	PECO Energy-Eddystone	No. 10 Gas Turbine	037	1	0.49	9,464
Delaware	PECO Energy-Eddystone	No. 20 Gas Turbine	038	1	0.48	7,560
Delaware	PECO Energy-Eddystone	No. 30 Gas Turbine	039	2	0.48	19,502
Delaware	PECO Energy-Eddystone	No. 40 Gas Turbine	040	1	0.49	9,450
Delaware	PECO Energy-Eddystone	No. 4 Boiler	041	249	0.28	2,089,539
Delaware	Kimberly-Clark	Boiler No. 9	034	12	0.52	264,600
Delaware	Kimberly-Clark	10 Culm Cogen. Fbc Plant	035	85	0.08	1,602,169
Delaware	Sun Refining & Marketing		089	86	0.09	1,211,002
Delaware	Sun Refining & Marketing		090	145	0.08	4,927,837
Elk	Penntech Papers, Inc.	B&W Model Pm106 Boiler #6	038	0	0.00	0
Elk	Penntech Papers, Inc.	B&W #81 Boiler	040	103	0.83	570,989
Elk	Penntech Papers, Inc.	B&W #82 Boiler	041	109	0.83	603,471
Erie	General Electric Co.	B&W Boiler No. 2	032	26	1.01	587,180
Erie	International Paper Company	Coal Fired Boiler No. 21	037	68	0.58	321,958
Erie	Norcon Power Partners	Turbine 1	001	50	0.07	1,483,488
Erie	Norcon Power Partners	Turbine 2	002	50	0.07	1,483,488
Erie	Penelec-Front Street	Erie City Iron Works No. 7	031	5	0.92	38,964
Erie	Penelec—Front Street	Erie City Iron Works No. 8	032	5	0.90	39,881

County	*Facility*	*Combustion Source Name*	*Point ID*	*Allowance*	*Baseline NO_x lb/MMBtu*	*Baseline MMBtu*
Erie	Penelec—Front Street	Comb. Eng. Boiler No. 9	033	134	0.57	1,033,388
Erie	Penelec—Front Street	Comb. Eng. Boiler No. 10	034	134	0.57	1,033,528
Greene	West Penn Power—Hatfield's Ferry	Babcock & Wilcox	031	3,978	1.04	15,502,912
Greene	West Penn Power—Hatfield's Ferry	Babcock & Wilcox	032	3,703	1.04	14,429,251
Greene	West Penn Power—Hatfield's Ferry	Babcock & Wilcox	033	2,160	1.04	8,416,290
Indiana	Penelec—Conemaugh	Boiler No. 1	031	3,295	0.76	20,130,686
Indiana	Penelec—Conemaugh	Boiler No. 2	032	4,197	0.76	25,543,024
Indiana	Penelec—Homer City	Boiler No. 1-Foster Whelr	031	3,167	1.20	11,325,278
Indiana	Penelec—Homer City	Boiler No. 2-Foster Whelr	032	3,987	1.20	15,382,211
Indiana	Penelec—Homer City	Boiler No. 3-B&W	033	2,931	0.62	21,951,003
Indiana	Penelec—Seward	Boiler No. 12 (B&W)	032	145	0.84	849,307
Indiana	Penelec—Seward	Boiler No. 14 (B&W)	033	146	0.83	809,011
Indiana	Penelec—Seward	Boiler No. 15 (Comb. Eng.)	931	673	0.75	4,155,275
Lackawanna	Archbald Power Corporation	Cogen		82	0.05	818,013
Lancaster	PP&L—Holtwood	Unit 17 Foster Wheeler	934	807	1.20	3,116,786
Lawrence	Penn Power Co.—New Castle	Foster Wheeler	031	108	0.91	553,994
Lawrence	Penn Power Co.—New Castle	B.W. Boiler	032	97	0.91	498,559
Lawrence	Penn Power Co.—New Castle	Babcock And Wilcox	033	185	0.91	947,292
Lawrence	Penn Power Co.—New Castle	Babcock And Wilcox	034	339	0.91	1,737,996
Lawrence	Penn Power Co.—New Castle	Babcock And Wilcox	035	622	0.91	3,183,091
Lehigh	PP&L—Allentown	CT 1		2	0.49	10,329
Lehigh	PP&L—Allentown	CT 2		3	0.49	13,752
Lehigh	PP&L—Allentown	CT 3		3	0.49	14,215
Lehigh	PP&L—Allentown	CT 4		3	0.49	12,745
Lycoming	PP&L—Williamsport	CT 1		3	0.49	14,633
Lycoming	PP&L—Williamsport	CT 2		3	0.49	14,083
Luzerne	Continental Energy Associates	Turbine		269	0.13	2,687,577
Luzerne	Continental Energy Associates	HRSG		129	0.20	1,288,248
Luzerne	UGI Corp.—Hunlock Power	Foster Wheeler	031	375	0.95	1,821,127
Luzerne	PP&L—Jenkins	CT 1		3	0.49	12,942
Luzerne	PP&L—Jenkins	CT 2		2	0.49	6,885
Luzerne	PP&L—Harwood	CT 1		3	0.49	14,194
Luzerne	PP&L—Harwood	CT 2		3	0.49	14,049
Monroe	Met Edison Shawnee		031	3	0.59	15,285
Montgomery	Merck Sharp & Dohme	Cogen II Gas Turbine	039	79	0.16	1,028,875
Montour	PP&L—Montour	Montour No. 1	031	3,576	0.85	17,029,683
Montour	PP&L—Montour	Montour No. 2	032	4,706	1.07	22,409,322
Montour	PP&L—Montour	Aux. Start-Up Boiler No. 1	033	9	0.17	44,436
Montour	PP&L—Montour	Aux. Start-Up Boiler No. 2	034	7	0.17	34,076
Northampton	Bethlehem Steel Corp.	Boiler 1 Boiler House 2	041	90	0.23	Confidential
Northampton	Bethlehem Steel Corp.	Boiler 2 Boiler House 2	042	90	0.23	Confidential
Northampton	Bethlehem Steel Corp.	Boiler 3 Boiler House 2	067	91	0.23	Confidential
Northampton	Met Edison Co.—Portland	Unit No. 1	031	463	0.59	3,593,611
Northampton	Met Edison Co.—Portland	Unit No. 2	032	*658*	0.66	4,578,297
Northampton	Met Edison Co.—Portland	Combustion Turbine No. 3	033	1	0.53	9,795
Northampton	Met Edison Co.—Portland	Combustion Turbine No. 4	034	6	0.53	40,931

County	Facility	Combustion Source Name	Point ID	Allowance	Baseline NO_x lb/MMBtu	Baseline MMBtu
Northampton	Northampton Generating Company	Boiler	001	210	0.10	4,208,112
Northampton	PP&L—Martins Creek	Foster-Wheeler Unit No. 1	031	493	1.01	3,329,831
Northampton	PP&L—Martins Creek	Foster-Wheeler Unit No. 2	032	461	0.91	3,112,136
Northampton	PP&L—Martins Creek	C-E Unit No. 3	033	837	0.51	*5,652,924*
Northampton	PP&L—Martins Creek	C-E Unit No. 4	034	741	0.51	*5,003,663*
Northampton	PP&L—Martins Creek	No. 4b Auxiliary Boiler	036	0	0.17	2,394
Northampton	PP&L—Martins Creek	Combustion Turbine No. 1	037	3	0.02	206,640
Northampton	PP&L—Martins Creek	Combustion Turbine No. 2	038	3	0.02	206,640
Northampton	PP&L—Martins Creek	Combustion Turbine No. 3	039	3	0.02	206,640
Northampton	PP&L—Martins Creek	Combustion Turbine No. 4	040	3	0.02	206,640
Northumberland	Foster Wheeler Mt. Carmel Cogen	Cogen	031	196	0.10	1,814,911
Philadelphia	PECO Energy		037	28	0.60	117,455
Philadelphia	PECO Energy		038	37	0.60	156,375
Philadelphia	PECO Energy—Delware		013	111	0.45	918,037
Philadelphia	PECO Energy—Delware		014	129	0.45	1,066,091
Philadelphia	PECO Energy—Delware		015	1	0.67	7,089
Philadelphia	PECO Energy—Delaware		016	1	0.67	9,452
Philadelphia	PECO Energy—Delaware		017	1	0.67	11,259
Philadelphia	PECO Energy—Delaware		018	2	0.67	15,012
Philadelphia	PECO Energy—Schuylkill		003	174	0.28	1,459,923
Philadelphia	PECO Energy—Schuylkill		007	1	0.67	9,285
Philadelphia	PECO Energy—Schuylkill		008	0	0.67	1,946
Philadelphia	Trigen Energy Co—Sansom		001	31	0.45	318,459
Philadelphia	Trigen Energy Co—Sansom		002	27	0.45	280,748
Philadelphia	Trigen Energy Co—Sansom		003	12	0.45	126,824
Philadelphia	Trigen Energy Co—Sansom		004	15	0.45	155,123
Philadelphia	Trigen Energy Co—Schuylkill		001	0	0.28	511,191
Philadelphia	Trigen Energy Co—Schuylkill		002	0	0.28	228,162
Philadelphia	Trigen Energy Co—Schuylkill		005	0	0.45	248,138
Philadelphia	U.S. Naval Base		098	1	0.14	14,294
Philadelphia	U.S. Naval Base		099	1	0.14	1,960
Philadelphia	Grays Ferry Project	Combustion Turbine		126		
Philadelphia	Grays Ferry Project	Heat Recovery Steam Gen		21		
Philadelphia	Grays Ferry Project	Boiler 25		80		
Schuylkill	Gilberton Power Company	Boiler		335	0.17	3,352,372
Schuylkill	Northeastern Power Company	CFB Boiler		202	0.06	2,022,148
Schuylkill	Northeastern Power Company	Aux Boiler		0	0.27	1,396
Schuylkill	Schuylkill Energy Resources	Boiler	031	350	0.20	4,349,117
Schuylkill	Westwood Energy Properties	Boiler		135	0.17	1,351,408
Schuylkill	Wheelabrator Frackville Energy Co	Boiler		205	0.14	2,046,694
Schuylkill	PP&L—Fishback	CT 1		2	0.49	8,272
Schuylkill	PP&L—Fishback	CT 2		2	0.49	7,217
Snyder	PP&L—Sunbury	Sunbury SES Unit 1a	031	295	0.98	1,455,641
Snyder	PP&L—Sunbury	Sunbury SES Unit 1b	032	295	0.98	1,455,641
Snyder	PP&L—Sunbury	Sunbury SES Unit 2a	033	295	0.83	1,455,641
Snyder	PP&L—Sunbury	Sunbury SES Boiler 2b	034	295	0.83	1,455,641

County	Facility	Combustion Source Name	Point ID	Allowance	Baseline NO_x lb/MMBtu	Baseline MMBtu
Snyder	PP&L—Sunbury	Sunbury SES Unit No. 3	035	681	0.93	3,363,299
Snyder	PP&L—Sunbury	Sunbury SES Unit No. 4	036	824	0.99	4,070,181
Snyder	PP&L—Sunbury	Diesel Generator 1	037	0	3.39	709
Snyder	PP&L—Sunbury	Diesel Generator 2	038	0	3.23	806
Snyder	PP&L—Sunbury	Combustion Turbine 1	039	3	0.49	14,581
Snyder	PP&L—Sunbury	Combustion Turbine 2	040	3	0.49	14,581
Tioga	Penelec—Tioga		031	3	0.48	30,267
Venango	Scrubgrass Power Plant	Unit 1	031	182	0.14	1,816,817
Venango	Scrubgrass Power Plant	Unit 2	032	179	0.15	1,790,997
Warren	Penelec—Warren	Boiler No. 1	031	76	0.62	569,825
Warren	Penelec—Warren	Boiler No. 2	032	73	0.64	546,534
Warren	Penelec—Warren	Boiler No. 3	033	77	0.61	572,007
Warren	Penelec—Warren	Boiler No. 4	034	80	0.61	596,377
Warren	Penelec—Warren		001	10	0.69	77,943
Washington	Duquesne Light Co.—Elrama	No. 1 Boiler	031	334	0.87	1,116,538
Washington	Duquesne Light Co.—Elrama	No. 2 Boiler	032	333	0.90	1,114,175
Washington	Duquesne Light Co.—Elrama	No. 3 Boiler	033	446	0.87	1,490,615
Washington	Duquesne Light Co.—Elrama	No. 4 Boiler	034	1,016	0.89	3,398,150
Washington	McGraw—Edison Co.	Foster-Wheeler	032	0	0.00	0
Washington	Washington Power Co.	Boiler 1		155	0.15	2,068,438
Washington	Washington Power Co.	Boiler 2		155	0.15	2,068,438
Washington	West Penn Power Co.—Mitchell	Combustion Eng Coal Unit	034	931	0.72	5,968,482
Wayne	Penelec—Wayne		031	11	0.84	62,736
Wyoming	Procter & Gamble Paper Products Co.	Westinghouse 251B10	035	246	0.68	1,654,800
York	Glatfelter, P.H. Co.	Number 4 Power Boiler	034	127	0.80	978,985
York	Glatfelter, P.H. Co.	Number 1 Power Boiler	035	85	0.80	653,626
York	Glatfelter, P.H. Co.	Number 5 Power Boiler	036	232	0.29	1,780,350
York	Met Edison Tolna		031	4	0.59	20,492
York	Met Edison Tolna		032	4	0.59	19,306
York	PP&L—Brunner Island	Brunner Island 2	032	1,474	0.69	9,319,539
York	PP&L—Brunner Island	Brunner Island Unit 1	931	1,294	0.67	8,178,891
York	PP&L—Brunner Island	Brunner Island Unit 3	933	2,913	0.78	18,411,970
York	Solar Turbines, Inc.	Turbine 1	031	33	0.19	355,420
York	Solar Turbines, Inc.	Turbine 2	032	33	0.19	355,248
York	Solar Turbines, Inc.	Turbine 3	033	33	0.19	357,626
York	Solar Turbines, Inc.	Turbine 4	034	33	0.19	360,280
York	Solar Turbines, Inc.	Turbine 5	035	33	0.19	357,488
York	Solar Turbines, Inc.	Turbine 6	036	32	0.19	351,077

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