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May 7, 1999

VIA FEDERAL EXPRESS

Environmental Quality Board
Rachel Carson State Office Building
400 Market Street, 15th Floor
Harrisburg, PA 17101

Re: Comments on the Proposed Interstate Ozone Transport Reduction Rule, 29 Pa. Bull. 1319 (March 6, 1999)

Dear Sir or Madam:

Enclosed please find the comments of Zinc Corporation of America ("ZCA") on the proposed Interstate Ozone Transport Reduction Rule, 29 Pa. Bull. 1319 (March 6, 1999). A one-page summary of these comments is included for the Board's convenience. These comments (excluding the attachment to the comments) and the summary also will be transmitted to you electronically on Monday, May 10, 1999.

Should you have any questions about these comments, please contact Ali Alavi, ZCA, Director, Environment, Health & Safety Performance at (724) 773-2212.

Sincerely,

Makram Jaber

Makram Jaber
Counsel for Zinc Corporation of America

Enclosures

Summary of Comments of
ZINC CORPORATION OF AMERICA
on the
Environmental Quality Board's Proposed Rule:
25 Pa. Code Chapters 123 and 145
Interstate Ozone Transport Reduction
29 Pa. Bull. 1319 (March 6, 1999)

Zinc Corporation of America ("ZCA") operates zinc manufacturing facilities in Monaca, Pennsylvania. ZCA's affected units under this proposed rule are two 600 mmBTU/hr boilers, each of which serves a generator with a nameplate capacity of 60 MW. The boilers principally are coal-fired, with a small amount of natural gas used for start up and to supplement the coal on occasions. The electricity is generated for the purpose of providing power to ZCA's zinc manufacturing equipment. ZCA submits the following comments:

- The EQB's classification of industrial electric generating units that produce electricity primarily for on-site industrial use as "electric generating units" or "EGUs" under the proposed rule is inconsistent with EPA's classification methodology, EPA's cost-effectiveness determination, and Pennsylvania's state trading program budgets in the NOx SIP Call. Like EPA, the EQB should classify industrial electric generating units as "non-EGUs" under the OTR trading program.

- The OTR Rule should include an inventory of affected units and initial allowance allocations to these units. Given the fact that the data necessary to calculate such initial allowances already is in the possession of the Department of Environmental Protection, there is no reason not to include the initial allowance allocations in the proposed rule.

- The OTR Rule's method for calculating initial allowance allocations for non-EGUs and yearly allowance allocations for all units starting in 2006 on the basis of the units' heat input in a single year is unfair and unworkable. Such a method renders operators too vulnerable to fluctuations in economic conditions or unexpected outages. ZCA recommends that the EQB calculate allowances for all units on the basis of an averaging methodology similar to the method used for calculating EGU initial allowances. For example, starting in 2006, yearly allowances should be allocated based on the average of the two highest amounts of the unit's heat input in the fifth, fourth, and third preceding years, rather than a single year as currently proposed.

- The NOx allowance transfer deadline should be moved to December 31 of each year to maintain consistency with the existing NOx trading program in Pennsylvania.

- ZCA supports the EQB's proposal to use the supplemental compliance pool primarily to allow the use of banked allowances from the existing program. ZCA recommends that the EQB allow the use of banked allowances created in any SIP Call state and sold to a company located in Pennsylvania.

Comments of

ZINC CORPORATION OF AMERICA

on the

Environmental Quality Board's Proposed Rule:

25 *Pa. Code* Chapters 123 and 145
Interstate Ozone Transport Reduction
29 Pa. Bull. 1319 (March 6, 1999)

Dated: May 7, 1999

INTRODUCTION AND SUMMARY OF COMMENTS

Zinc Corporation of America ("ZCA") submits the following comments on the Environmental Quality Board's ("EQB") proposed rule entitled "Interstate Ozone Transport Reduction," 29 Pa. Bull. 1319 (March 6, 1999) (hereinafter "OTR Rule"). ZCA operates zinc manufacturing facilities in Monaca, Pennsylvania. ZCA's affected units under this proposed rule are two 600 mmBTU/hr boilers, each of which serves a generator with a nameplate capacity of 60 MW. The boilers principally are coal-fired, with a small amount of natural gas used for start up and to supplement the coal on occasions. The electricity is generated for the purpose of providing power to ZCA's zinc manufacturing equipment.

ZCA's comments address the following issues:

- The EQB's classification of industrial electric generating units that produce electricity primarily for on-site industrial use as "electric generating units" or "EGUs" under the proposed rule is inconsistent with EPA's classification methodology, EPA's cost-effectiveness determination, and Pennsylvania's state trading program budgets in the NOx SIP Call. Like EPA, the EQB should classify industrial electric generating units as "non-EGUs" under the OTR trading program.

- The OTR Rule should include an inventory of affected units and initial allowance allocations to these units. Given the fact that the data necessary to calculate such initial allowances already is in the possession of the Department of Environmental Protection, there is no reason not to include the initial allowance allocations in the proposed rule.

- The OTR Rule's method for calculating initial allowance allocations for non-EGUs and yearly allowance allocations for all units starting in 2006 on the basis of the units' heat input in a single year is unfair and unworkable. Such a method renders operators too vulnerable to fluctuations in economic conditions or unexpected outages. ZCA recommends that the EQB calculate allowances for all units on the basis of an averaging methodology similar to the method used for calculating EGU initial allowances. For example, starting in 2006, yearly allowances should be allocated based on the average of the two highest amounts of the unit's heat input in the fifth, fourth, and third preceding years, rather than a single year as currently proposed.

- The NOx allowance transfer deadline should be moved to December 31 of each year to maintain consistency with the existing NOx trading program in Pennsylvania.

- ZCA supports the EQB's proposal to use the supplemental compliance pool primarily to allow the use of banked allowances from the existing program. ZCA recommends that the EQB allow the use of banked allowances created in any SIP Call state and sold to a company located in Pennsylvania.

COMMENTS

I. INDUSTRIAL ELECTRIC GENERATING UNITS THAT PRODUCE ELECTRICITY PRIMARILY FOR INTERNAL USE SHOULD BE CLASSIFIED AS NON-EGUs.

The OTR Rule in large part follows the model NOx trading rule codified at 40 C.F.R. Pt. 96 and promulgated by EPA in the NOx SIP Call rulemaking.[1] The most significant difference between the two rules, however, is in the applicability of the OTR Rule to electric generating units ("EGU") and non-electric generating units ("non-EGU").[2] Under the OTR Rule, any unit that serves an electric generator with a nameplate capacity greater than 15 MW is an EGU, regardless of the purpose of the electricity generated. Thus, an industrial electric generating unit, such as ZCA's, would be regulated as an EGU, even though the unit generates

[1] The final rule entitled "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," 63 Fed. Reg. 57356 (Oct. 27, 1998), is commonly referred to as the NOx SIP Call.

[2] The OTR Rule does not formally define the two terms, though the rule uses the terms in connection with the state budget. See, e.g., OTR § 145.40 (state trading program budget). Presumably, EGUs and non-EGUs are covered in the OTR Rule under sections 145.5(1) and 145.4(2), respectively. An EGU thus would be defined as "[a]ny unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than or equal to 15 MWe." Id. § 145.4(1). A non-EGU is any unit that is not an EGU "and that has a maximum design heat input greater than or equal to 250 mmBtu/hr." Id. § 145.4(2). The EQB should formally define the two terms in the final OTR Rule.

electricity primarily for internal use at the industrial facility. Under the NOx SIP Call, however, EPA classified such units as non-EGUs.[3]

The OTR Rule's classification system thus is inconsistent with EPA's classification system under the NOx SIP Call. This inconsistency imposes an unfair burden on industrial electric generating units and creates an anomaly with respect to the state trading program budget calculation for Pennsylvania.

A. The OTR Rule Classification System Is Inconsistent with EPA's Cost Effectiveness Determination.

The foundation of the NOx SIP Call is the cost effectiveness determination that EPA conducted in that rulemaking. According to EPA, the levels of emission control that the NOx SIP Call requires and its scope are such that affected units need only install "highly cost-effective control options" to comply with the rule. "To assure equity among the various source categories and the industries they represent, EPA considered the cost effectiveness of controls for each source category separately throughout the SIP Call region." 63 Fed. Reg. at 57399. For this reason, EPA considered separately (i) "boilers and turbines serving

[3] Even though industrial electric generating units, such as ZCA's, were classified as non-EGUs in EPA's emissions inventories, the language of EPA's model trading rule appears to classify industrial utility units as EGUs if they sell any electricity to the grid. See 63 Fed. Reg. at 57518 (to be codified at 40 C.F.R. § 96.4(a)(1)). Recognizing the oversight, EPA clarified in a recent notice that "[f]or units that commenced operation before January 1, 1999, EPA will classify as an EGU any boiler or turbine that sells any electricity to the grid under firm contract." Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport; Final Rule, at 308-09 (signed May 3, 1999; available at http://www.epa.gov/ttn/oarpg/ramain.html; to be published in the Federal Register) (emphasis added). Under EPA's classification, "most existing industrial units that sell small amounts of electricity will also not be considered EGUs, because most of these units do not sell electricity under firm contract." Id. at 306. "The EPA intends to make parallel clarifications to the definition of EGU under the NOx SIP Call rulemaking." Id. at 307. Thus, it is clear that EPA intended to classify existing industrial electric generating units as non-EGUs, even if these units sold small amounts of electricity to the grid.

generators that produce electricity for sale to the grid," and (ii) industrial "boilers and turbines that exclusively generate steam and/or mechanical work . . ., or produce electricity primarily for internal use and not for sale." Id. (emphasis added). The former category comprises EGUs, while the second category comprises non-EGUs. EPA explained that "this categorization better reflects the industrial sectors served." Id. EPA's analyses then showed that, to maintain equity among source categories, EGUs should be controlled to achieve an average emission rate of 0.15 lb/mmBtu, while non-EGUs – including industrial electric generating units – should be controlled to achieve an average emission rate of 0.17 lb/mmBtu.

The EQB should modify the applicability provisions of the OTR Rule to include industrial electric generating units (i.e., units that serve generators that produce electricity primarily for internal use and not for sale) in the non-EGU category. Such a modification would, as EPA recognized, "better reflect[] the industrial sectors served." The owners of industrial electric generating units operate under different constraints and in a different market than traditional public utilities. The principal business of ZCA, for example, is not the sale, transmission, or distribution of electricity. It is to produce and sell zinc metal and zinc oxide for use in a wide variety of consumer products (e.g., UV protection, tires, adhesives, pigments, and galvanized steel).[4] Unlike public utilities, which can pass on the cost of NOx

[4] Like most industrial electric generating units, ZCA's units are interconnected with the local electric grid. Interconnection often is necessary in order to control the power voltage and frequency of the electricity generated and to provide the industrial unit with backup and emergency power. The local public utility typically requires the industrial owner to provide, in return, certain amounts of electricity to the grid, if available. Such interconnection agreements are not considered "firm contracts" because small amounts of electric power are provided to the grid only if available. ZCA has such an arrangement with Duquesne Light Company. In differentiating between EGUs and non-EGUs, the EQB should make it clear that only units that serve generators that produce electricity primarily for internal use would be considered non-EGUs.

controls to their customers through ratemaking and other mechanisms, ZCA cannot do so because it has no control over the price of zinc products. Indeed, the price of ZCA's products is based on the price of zinc as indicated on the London Metal Exchange and is independent of ZCA's production cost.

This is especially significant, in light of the expected cost of compliance with the OTR Rule. Given the size of ZCA's units, which are substantially smaller than those typically owned and operated by public utilities, the loss of economies of scale makes employing selective catalytic reduction or other available NOx control technology prohibitively expensive for ZCA's units. Purchasing allowances on the open market also is very expensive, and much more so than anticipated by EPA in the NOx SIP Call.[5] Conservative estimates are upwards of $1.5 million per year for ZCA to purchase allowances under this proposal at a cost of $5000/ton NOx.

If industrial electric generating units are classified as EGUs, these units will be allocated fewer NOx allowances than comparable non-EGUs. Therefore, by classifying industrial electric generating units as EGUs, the OTR Rule imposes a disproportionate economic hardship on ZCA and other industrial owners of on-site electric generating units. Especially in light of EPA's classification methodology and cost effectiveness determination in the NOx SIP Call, the EQB should not adopt a different classification in the absence of any compelling state interest. Cf. Governor Ridge's Executive Order 1996-1 (providing that Pennsylvania's environmental regulations be no more stringent than federal regulations, unless

[5] In the NOx SIP Call, EPA anticipated that the allowance cost would be approximately $2,000. NOx allowances under the existing NOx trading rule in Pennsylvania, 25 Pa. Code ch. 123, are trading in the $5,000 to $6,000 range.

justified by a "compelling and articulable" Commonwealth interest or authorized by State law). There is no compelling state interest here to deviate from the federal requirements.

B. The OTR Rule Classification System Is Inconsistent with Pennsylvania's State Trading Program Budgets Under the NOx SIP Call.

In addition to the inequity of classifying industrial electric generating units as EGUs, such a classification also would be inconsistent with the state trading program budgets allocated in the NOx SIP Call to Pennsylvania. Pennsylvania's NOx budgets of 52,000 tons and 5,600 tons per season for EGUs and non-EGUs, respectively, are based on the contribution of each affected unit to the state's base budget. That is, EPA inventoried all EGU and non-EGU units in the state, and assigned the state budgets on the basis of uncontrolled NOx emissions from these units and an assumed control factor. In doing so, EPA included ZCA's units, as well as other industrial electric generating units in the state, in the non-EGU database for Pennsylvania. In other words, the 5,600 tons state trading program budget for non-EGUs includes the base contribution of ZCA's units, as well as any other industrial electric generating units listed in EPA's non-EGU database.

By reclassifying ZCA's units as EGUs, the OTR Rule creates an anomaly: The emissions from these units will be counted against the state's EGU budget, even though their baseline contribution was counted in the non-EGU state budget. As a result of this classification, there will be fewer non-EGUs that must meet the 5,600-ton non-EGU budget than that budget is based upon, and there will be more EGUs that must meet the 52,000-ton EGU budget. Thus, non-EGUs will receive even more allowances each year than the NOx SIP Call assumed, and EGUs will receive fewer allowances than the NOx SIP Call assumed. This

compounds the unfairness of reclassifying industrial electric generating units as EGUs and, additionally, renders the entire allowance system unfair for all involved.

* * * * *

Classification of industrial electric generating units as EGUs under the OTR Rule is inconsistent with EPA's classification methodology, EPA's cost-effectiveness determination, and EPA's base inventories in the NOx SIP Call. To avoid the inequities that result from such a classification, the EQB should modify the proposed rule to include in the non-EGU category industrial electric generating units that produce electricity primarily for internal, industrial use.

II. THE OTR RULE SHOULD INCLUDE AN INVENTORY OF AFFECTED UNITS AND INITIAL ALLOWANCE ALLOCATIONS TO THESE UNITS.

Unlike the existing NOx trading rule in Pennsylvania, 25 Pa. Code ch. 123, the OTR Rule does not contain a listing of affected units and allowance allocations. The preamble states that this difference is due to the fact that the OTR Rule "establishes a formula for calculation of allowances in Section 142.42." 29 Pa. Bull. at 1321. This fact does not justify the total omission of an inventory and initial allowance allocations in the proposed rule. While ZCA understands that allowance allocations for 2006 and any year thereafter will be adjusted yearly and thus cannot be determined at this time, there is no impediment to including in the rule allowance allocations for the years 2003, 2004, and 2005. As the proposed rule specifies, allowance allocations for the first three years of the program are based on actual utilization (heat input) during 1995 to 1997 for EGUs and 1995 for non-EGUs. These data currently are in the possession of the Department of Environmental Protection ("DEP") and should be used to publish an initial allowance allocation database for affected units.

The publication of such a database would be helpful to the regulated community in three important ways. First, a Pennsylvania company that will be subject to the NOx budget trading program cannot fully and completely evaluate this proposed rule without knowing with some certainty how the rule would affect the company. The amount of allowances allocated to that company for the first three years of the program – an amount that should be readily available from DEP's current databases – is a critical piece of information in that respect. Without such information, the company has no way of determining how the rule would affect it.

Second, information about allowance allocations for the first three years of the program should be made available to affected entities as early as possible to allow these entities to take the necessary steps to comply with, or at least evaluate compliance strategies for, the OTR Rule. Since this data is available now, there is no reason not to make it part of the proposed rule at this time.

Finally, many in the regulated community naturally have concerns about the accuracy of the data that will be used for allowance allocation purposes. For example, even though ZCA has diligently submitted emission statements to DEP over the years, and EPA supposedly based its emissions inventories in the NOx SIP Call on the data provided by DEP, ZCA discovered egregious mistakes in EPA's databases in the data pertaining to ZCA's units.[6] By

[6] ZCA submitted corrected data to EPA, with a copy to DEP, in response to EPA's notice reopening the period for emissions inventory revisions, 63 Fed. Reg. 71220 (Dec. 24, 1998). A copy of those corrections is attached to these comments on the OTR Rule. Presumably, EPA will correct its emissions inventory and, therefore, the states' budgets, on the basis of the corrections submitted by ZCA and others. ZCA notes, however, that the OTR Rule has no mechanism to adjust the state trading program budgets in accordance with EPA's corrected budgets. The OTR Rule should include a mechanism to do so automatically, for example incorporating by reference the state's trading program budget promulgated by EPA, rather than

all accounts, the inaccuracy of EPA's data is by no means confined to ZCA's units. By including an initial database and allowance allocations for Pennsylvania units in the OTR Rule, the EQB would alleviate the regulated community's concerns about the accuracy of the data in DEP's possession or, if necessary, would allow ample time for correction of the data before the rule takes effect.

For these reasons, ZCA urges the EQB to re-propose the OTR rule and include in that new proposal a listing of affected units and initial allowance allocations for the first three years of the program.

III. ALLOWANCE ALLOCATIONS SHOULD NOT BE BASED ON THE UNIT'S HEAT INPUT IN A SINGLE YEAR, BUT SHOULD BE AVERAGED OVER TWO OR MORE YEARS.

Under the OTR Rule, the initial allowance allocations for EGUs is based on "the average of the two highest amounts of the unit's heat input for the control periods in 1995, 1996, and 1997." OTR § 145.42(a)(1)(i). This method of allowance allocation appears to recognize that economic conditions or unexpected operating constraints (e.g., unexpected outages) in any one year may artificially decrease a unit's heat input for that year. For this reason, the rule uses an average of the two highest years in the 1995-1997 period to establish initial allowance allocations for EGU units. Unexplainably, however, the rule does not treat non-EGUs similarly. For non-EGUs, the heat input for the year 1995 constitutes the exclusive basis of initial allowance allocations.

Moreover, starting with the year 2006, yearly allowance allocations for all units – EGUs and non-EGUs alike – will be based exclusively on "the unit's heat input for the control

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listing in the proposed rule the specific budgets as they currently stand (i.e., 52,000 tons for EGUs and 5,600 tons for non-EGUs).

period in the year that is four years before the year for which the NOx allocation is being calculated." OTR § 145.42(a)(1)(ii). This method of calculating allowances is unfair and unworkable, given the likelihood of fluctuation in economic conditions or unexpected outages. For example, if in the year 2002, ZCA faces a decrease in demand for its zinc products due to global economic conditions and, therefore, does not generate "normal" levels of electricity to supply to the zinc manufacturing operation compared to other years (resulting in a lower than normal heat input), ZCA would be penalized in 2006 by being allocated fewer allowances than anticipated or required for that year. If, in this example, the global economy has rebounded by 2006, ZCA would be at a crippling disadvantage with respect to its competitors because it must purchase expensive allowances to cover the allowance deficit.

To alleviate this problem, ZCA recommends that the EQB base the rule's allowance allocation formula for all units on an averaging methodology similar to the EGU initial allowance allocations under Section 145.42(a)(1)(i). The same allowance allocation base period should be used for calculating non-EGU initial allowances. Moreover, starting in 2006, yearly allowances should be allocated based on the average of the two highest amounts of the unit's heat input in the fifth, fourth, and third preceding years.

IV. THE NOx ALLOWANCE TRANSFER DEADLINE SHOULD BE MOVED TO DECEMBER 31.

The proposed rule adopts November 30 as the NOx allowance transfer deadline each year. Under the current NOx trading rule in Pennsylvania, 25 Pa. Code ch. 123, December 31 is the NOx allowance transfer deadline. ZCA recommends maintaining the December 31 deadline in the OTR Rule for purposes of consistency with the existing program and to streamline administrative management of accounts by owners and operators of affected units.

V. THE EQB SHOULD USE THE SUPPLEMENTAL COMPLIANCE POOL PRIMARILY TO ALLOW THE USE OF BANKED ALLOWANCES FROM THE EXISTING PROGRAM AND SHOULD ALLOW THE USE OF BANKED ALLOWANCES CREATED IN ANY SIP CALL STATE.

In response to the EQB's request for comments on the issue of banked allowances, ZCA urges the EQB to use the supplemental compliance pool as authorized (and proposed) by EPA, primarily to allow the transfer of banked allowances from the existing NOx trading system, 25 Pa. Code § 123.110(a)(3), into the OTR program. Any other use would be unfair to those affected units in Pennsylvania that reduce their emissions below existing requirements. Thus, ZCA recommends that the EQB maintain the banked allowances transition scheme in the proposed rule.

Moreover, given the acknowledged regional character of the ozone problem, ZCA recommends that the EQB authorize the use of banked allowances created in other states (within the SIP Call region) and sold to companies located in Pennsylvania. This would encourage industry everywhere in the SIP Call region to reduce NOx emissions as early as possible, thus benefiting air quality in the entire region. It also increases the flexibility of the program, which is critical considering the significant cuts in NOx emissions that the program requires.

ATTACHMENT

Comments of

ZINC CORPORATION OF AMERICA

on the

NOx Emissions Inventories in the U.S. Environmental Protection Agency's Actions:

Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule. 63 Fed. Reg. 57356 (Oct. 27, 1998).
Docket No. A-96-56

Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Transport of Ozone; Proposed Rule. 63 Fed. Reg. 56292 (Oct. 21, 1998).
Docket No. A-97-43

Federal Implementation Plans To Reduce the Regional Transport of Ozone; Proposed Rule. 63 Fed. Reg. 56394 (Oct. 21, 1998)
Docket No. A-98-12

Dated: February 22, 1999

INTRODUCTION

Zinc Corporation of America ("ZCA") submits the following comments on the U.S. Environmental Protection Agency's ("EPA") NOx emissions inventories in the NOx SIP Call and related rulemakings.[1] ZCA operates zinc manufacturing facilities in Pennsylvania. Several industrial units owned and operated by ZCA are listed in the non-electric generation unit ("non-EGU") inventory compiled by EPA.[2] These comments address data corrections for the "large" units listed in the inventory under ZCA's ownership.

CORRECTIONS

The non-EGU emissions inventory has four entries listed as "large" non-EGU units under ZCA's ownership. These entries in fact correspond to two 600 mmBtu/hr boilers—assigned Point Id Codes 034 and 035—located at ZCA's Monaca, Pennsylvania facility. The boilers are primarily coal-fired. A small amount of natural gas is used for startup and to supplement the coal on occasions. Thus, although the heat throughput is reported separately for the coal and gas used in each boiler (which explains why each boiler is listed as two separate items in the inventory), NOx emission monitoring data are collected for each boiler as one unit. For this reason, it is inaccurate to report NOx emissions for the coal and gas usage

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[1] The NOx SIP Call and related rulemakings are the three actions related to reducing regional transport of Ozone listed on the cover page of these comments. These three actions will be collectively referred to as the "NOx SIP Call" or the "SIP Call" in these comments. EPA reopened until February 22, 1999 the comment period for emissions inventory corrections in these actions. See Correction and Clarification to the Finding of Significant Contribution and Rulemaking for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 71220 (Dec. 24, 1998); Reopening of Emissions Inventory Comment Periods for the Findings of Significant Contribution and Rulemakings on Section 126 Petitions and Federal Implementation Plans for Purposes of Reducing Interstate Transport of Ozone; Proposed Rules, 64 Fed. Reg. 2416 (Jan. 13, 1999).

[2] This inventory was obtained from the file pa_xls.zip contained in EPA's site at the following address: ftp.epa.gov/pub/scram001/modelingcenter/budget.

separately. Accordingly, NOx emissions are reported for each boiler only once in these comments, as detailed below. The data pertaining to the two boilers in the inventory are also incorrect in several other respects. Table 1 lists the data pertaining to these units and highlights the corrected data entries. The categories of data for which ZCA submits corrections and the supporting documentation for these corrections are discussed below.

A. 1995 Ozone Season Emissions and Control Efficiency

The baseline for the NOx budget calculations are the NOx emissions during the 1995 ozone season. Rather than including actual 1995 emissions for ZCA's boilers, however, EPA appears to have estimated 1995 emissions on the basis of actual 1990 emissions. Specifically, EPA apparently assumed that 1995 emissions are approximately 95 percent of 1990 emissions (this conclusion is based on a comparison of actual 1990 emissions from the boilers and the 1995 emissions listed in EPA's emissions inventory). EPA also assumed that 1995 emissions are uncontrolled; that is, EPA listed a 1995 control efficiency of zero. EPA's estimates are incorrect and underestimate actual 1995 uncontrolled emissions.

Table 1 lists actual average daily NOx emissions during the 1995 ozone season. The supporting documentation for this data is included as Attachment 1, and consists of the relevant pages from ZCA's 1995 annual emissions statement, as submitted to the Pennsylvania Department of Environmental Protection ("PADEP"). Table 1 also lists a 1995 control efficiency factor of 0.5 (or 50 percent) for ZCA's boilers. This control efficiency factor reflects the implementation of RACT controls for these units, in accordance with a RACT operating permit issued by PADEP on December 29, 1994. The control efficiency factor of 0.5 for ZCA's boilers was obtained as follows: (i) The actual NOx emission rate in lb/mmBtu

for the 1995 ozone season was calculated on the basis of actual, reported[3] values of daily NOx emissions in June-August 1995 and the heat input during the same period—the result of this calculation yields a NOx emission rate of 0.4 lb/mmBtu; (ii) the uncontrolled emission rate from ZCA's large units is 0.8 lb/mmBtu[4]; and (iii) the RACT control efficiency factor for 1995 was calculated as the ratio of actual to uncontrolled emission rates. The calculated RACT control efficiency of 50 percent is consistent with the default NOx RACT control efficiency listed for industrial boilers with SCC code 10200202 in the Technical Support Document for the emissions inventory. See EPA, Development of Modeling Inventory and Budgets for Regional NOx SIP Call, table III-1 (Sep. 24, 1998).

B. Seasonal Throughputs

Table 1 lists the seasonal throughputs for ZCA's units based on actual 1995 throughput data. The actual 1995 throughput data was included in ZCA's 1995 annual emissions statements, as submitted to PADEP (Attachment 1). The seasonal throughputs listed in Table 1 were calculated by summing the actual throughputs during each season and dividing the result by the total throughput for the year.

C. Times of Operation

There are several errors in the times of operations listed in EPA's emissions inventory for ZCA's boilers. The most glaring errors are for the two units listed under Point Id Code 034, which corresponds to one of the boilers at the facility. EPA's emissions inventory indicates that Boiler 034 operates only 6 days per week. This is incorrect. The inventory lists

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[3] See 1995 annual emissions statement in Attachment 1.

[4] The 0.8 lb/mmBtu uncontrolled emission rate for ZCA's boilers is reflected as the baseline emission rate in ZCA's RACT permit as well as PADEP's NOx allowance allocation to ZCA's units in the implementation of the OTC MOU, see 27 Pa. Bull. 56,83, 5695 (Nov. 1, 1997).

the number of weeks of operation for boiler 034 as zero, which is also incorrect. Both of these errors cause EPA to underestimate ZCA's baseline NOx emissions. ZCA operates both of its boilers continuously; that is, 24 hours per day, 7 days per week, 52 weeks per year. Accordingly, ZCA requests that EPA modify its emissions inventory to reflect actual times of operations for the two boilers, as shown in Table 1.[5]

D. 1995-2007 Growth Factor

EPA estimated uncontrolled NOx emissions for the year 2007 by applying a "growth factor" to 1995 baseline emissions. According to the technical support document describing the budget calculation methodology, EPA used state-by-state, industry-specific Bureau Of Economic Analysis data from 1990 to 1995 and economic projections for the period 1995-2007 to establish the growth factors. Moreover, EPA relied on the first two digits of the SIC code to establish the industry-specific factors. There are several shortcomings in EPA's analysis.

First, past economic performance—and even future economic performance—is not necessarily related to NOx emissions. NOx emissions for ZCA depend on production, which may or may not be proportionally related to economic performance (depending on world-wide or domestic price of zinc). Second, by including ZCA with primary metal manufacturers (i.e., SIC code with first two digits 33), which are dominated in Pennsylvania by the steel industry, EPA assumed that ZCA would experience a 16% contraction from 1995-2007 (i.e., the growth factor for ZCA's Pennsylvania units was assumed to be 0.84). ZCA operates a zinc manufacturing facility, however, and it was not affected by the decline in production

[5] For example, in 1995, ZCA operated both boilers 7 days per week, as reported in ZCA's 1995 emission statement submitted to PADEP. Due to outages for maintenance and unexpected repairs, however, the two boilers operated for a total of 8,351 and 8,329 hours, respectively. If converted to weeks (on the basis of 24-hour days), the two boilers operated in

experienced by the steel industry in the United States. While the U.S. steel industry has experienced a decline in production during this decade, the U.S. zinc industry has in fact experienced positive growth in the same time period. Indeed, industry statistics show a total increase in zinc production of about 8 percent from 1990 to 1998, or approximately a yearly average growth of 1 percent. This growth rate was highest in the last few years, averaging a yearly 2 percent growth from 1995 to 1998.[6] ZCA's performance is consistent with these industry-wide growth rates. ZCA reasonably—and conservatively—expects an average yearly growth factor of 1 percent to continue through the next decade.[7] Accordingly, ZCA requests that EPA modify its emissions inventory to reflect a more realistic 1995-2007 growth factor for the zinc manufacturing industry in Pennsylvania of 1.12 (corresponding to a yearly average increase of 1 percent over 12 years).

1995 for about 50 weeks each.

[6] See International Lead & Zinc Study Group, Lead & Zinc Statistics: Monthly Bulletin of the International Lead & Zinc Study Group, Vol. 35 No. 1 (Jan. 1995) & Vol. 39 No. 1 (Jan. 1999) (reporting yearly zinc production obtained from the U.S. Department of Commerce); CRU International Ltd., Zinc Quarterly Industry & Market Outlook (Jan. 1999) [hereinafter Zinc Quarterly].

[7] This growth rate is conservative and consistent with industry-wide forecasts. See, e.g., Zinc Quarterly (projecting an average growth of about 2.2 percent from 1998 to 2003).

CONCLUSION

ZCA submits in these comments accurate and supported data for its large non-EGU units in Pennsylvania. ZCA therefore requests that EPA correct the NOx emissions inventory in the SIP Call on the basis of the data submitted in these comments and make the appropriate resulting corrections in the budget calculations and NOx allowance allocations in the SIP Call, FIP, and section 126 rulemakings. The corrected NOx budget contributions for Boilers 034 and 035 are 281.9 and 278.0 tons, respectively.[8]

[8] The budget contributions for the units are calculated in accordance with the following formula: sbnox = dnox95 x 153 x gf9507 / (1 / noxce95) x (1 - noxce07b); where all terms are as defined in EPA's emissions inventory spreadsheets. The resulting budget contributions listed in the text above are based on the corrected data, including a 1995-2007 growth factor (gf9507) of 1.12, submitted in these comments. Using the corrected emission data and EPA's assumed—and erroneous—growth factor of 0.84 yields budget contribution for Boilers 034 and 035 of 211.4 and 208.5 tons, respectively.

TABLE 1
NOx SIP Call Emission Inventory Data
Correction for Large non-EGUs Owned by Zinc Corporation of America

fipsst	fipscnty	plantid	plant	point id	Segment	scc	newsize	boilcap	winthru	sprthru	sumthr	falthru	hours	days	weeks	dnox95	noxce95	gf9507
42	007	32	ZCA	34	1	10200202	L	251	12	27	29	32	24	6	0	3.1977	0	0.84
42	**007**	**32**	**ZCA**	**34**	**1**	**10200202**	**L**	**600**	**25**	**26**	**26**	**22**	**24**	**7**	**52**	**2.0565**	**0.5**	**1.12**
42	007	32	ZCA	34	2	10200601	L	251	12	27	29	32	24	6	0	0.0011	0	0.84
42	**007**	**32**	**ZCA**	**34**	**2**	**10200601**	**L**	**600**	**25**	**26**	**26**	**22**	**24**	**7**	**52**	**incl. w/ seg. 1**		**1.12**
42	007	32	ZCA	35	1	10200202	L	251	32	24	19	25	24	7	48	3.5526	0	0.84
42	**007**	**32**	**ZCA**	**35**	**1**	**10200202**	**L**	**600**	**23**	**25**	**25**	**26**	**24**	**7**	**52**	**2.0280**	**0.5**	**1.12**
42	007	32	ZCA	35	2	10200601	L	251	32	24	19	25	24	7	48	0.0040	0	0.84
42	**007**	**32**	**ZCA**	**35**	**2**	**10200601**	**L**	**600**	**23**	**25**	**25**	**26**	**24**	**7**	**52**	**incl. w/ seg. 1**		**1.12**

Notes:

1. All data fields are as defined in EPA's NOx Emissions Inventory Spreadsheets
2. Data currently listed in the NOx emissions inventory are shown in normal-type font
3. Corrected Data (on the basis of 1995 emission statement submitted to PADEP) are shown in bold-type font
4. ZCA is Zinc Corporation of America
5. The Winter, Spring, Summer, and Fall Throughput Percentages for boilers 034 and 035 are calculated using the monthly tons of coal throughput reported for 1995
6. The 1995 Typical Ozone Season Daily NOX Emissions (tons) are the June-August average daily emissions reported on the 1995 emission statement (in lb/day) divided by 2000 pounds/ton
7. The 1995 control efficiency is calculated on the basis of actual 1995 NOx emissions of 0.4 lb/mmBtu and and uncontrolled emission rate of 0.8 lb/mmBtu

ATTACHMENT 1

SUPPORTING DOCUMENTATION

Note: This attachment consists of copies of the following pages from ZCA's 1995 emission statement submitted to PADEP on February 29, 1996:

- Page 2: Data pertaining to Boiler 034;
- Page 3: Data pertaining to Boiler 035;
- Page 22: certification

ZINC CORPORATION OF AMERICA
POTTER TOWNSHIP

TAX ID - PLANT CODE 22-2370906-02
AFS NUMBER 420070032

Map Listing for Source: 034 (* denotes a shared facility)

034——>C08——>C01——>C02——>C03——>S01*

From	To	% Flow	Begin Date	End Date
Comb: 034	Ctrl: C08	100	JAN-01	DEC-31
Ctrl: C08	Ctrl: C01	100	JAN-01	DEC-31
Ctrl: C01	Ctrl: C02	100	JAN-01	DEC-31
Ctrl: C02	Ctrl: C03	100	JAN-01	DEC-31
Ctrl: C03	Stck: S01	100	JAN-01	DEC-31

SOURCE: **034** **COAL BOILER #1** RATED INPUT (MMBTU/HR): **600.0**
PERMIT NO: **04306004** DATE INSTALLED: **01-MAY-57** SCC: **10200202**
FUEL: **BITUMINOUS** %SULFUR **0.56** %ASH **10** BTU/LB-GAL-CUFT **13,163**

SCHEDULE 1 MONTHLY THROUGHTPUTS IN TONS

DATE EFFECTIVE:	01/01/95	JAN 12715	FEB 10309	MAR 11738	JUNE-AUG	
DATE END:	12/31/95	APR 13172	MAY 11175	JUN 10984	DAILY THRU	
DAYS PER WEEK:	7	JUL 12565	AUG 12858	SEP 10864	RATE 398	
TOTAL DAYS:	348	OCT 8631	NOV 11660	DEC 12967	UNITS Tons	
TOTAL HOURS:	8351					

FUEL: **NATURAL GAS** SCC: **20100201**
%SULFUR **0.0** %ASH **0.0** BTU/LB-GAL-CUFT **1,030**

SCHEDULE 1 MONTHLY THROUGHTPUTS IN THOUSAND CUBIC FEET

DATE EFFECTIVE:	-	JAN 904	FEB 1039	MAR 1838	JUNE-AUG	
DATE END:	-	APR 499	MAY 1534	JUN 905	DAILY THRU	
DAYS PER WEEK:	-	JUL 632	AUG 1117	SEP 481	RATE 29	
TOTAL DAYS:	-	OCT 1262	NOV 1228	DEC 947	UNITS MCF	
TOTAL HOURS:	As necessary					

CHANGES IN FUEL(S) USED, CONTROL DEVICES(S) OR EXHAUST Implemented RACT 05/26/95

ACTUAL EMISSION ESTIMATES (TONS/YR)

PM10	146	CALCULATION METHOD CODE	3
SOX	1273	CALCULATION METHOD CODE	14
NOX	736	CALCULATION METHOD CODE	14
VOC	4.9	CALCULATION METHOD CODE	10
CO	43	CALCULATION METHOD CODE	10

JUNE-AUG (LBS/DAY) FOR EMISSION STATEMENTS: NOX 4113 VOC 28

ZINC CORPORATION OF AMERICA
POTTER TOWNSHIP

TAX ID - PLANT CODE 22-2370906-02
AFS NUMBER 420070032

Map listing for Source: 035 **(* denotes a shared facility)**

035——>C09——>C04——>C05——>C06——>S01*

From	To	% Flow	Begin Date	End Date
Comb: 035	Ctrl: C09	100	JAN-01	DEC-31
Ctrl: C09	Ctrl: C04	100	JAN-01	DEC-31
Ctrl: C04	Ctrl: C05	100	JAN-01	DEC-31
Ctrl: C05	Ctrl: C06	100	JAN-01	DEC-31
Ctrl: C06	Stck: S01	100	JAN-01	DEC-31

SOURCE: **035** **COAL BOILER #2** RATED INPUT (MMBTU/HR): **600.0**
PERMIT NO: **04306004** DATE INSTALLED: **01-MAY-57** SCC: **10200202**
FUEL: **BITUMINOUS** %SULFUR **0.0** %ASH **0.0** BTU/LB-GAL-CUFT **13,133**

SCHEDULE 1 MONTHLY THROUGHTPUTS IN TONS

DATE EFFECTIVE:	01/01/95	JAN	9635	FEB	11887	MAR	11471
DATE END:	12/31/95	APR	13584	MAY	11715	JUN	11391
DAYS PER WEEK:	7	JUL	12805	AUG	12419	SEP	11360
TOTAL DAYS:	347	OCT	13804	NOV	12541	DEC	12545
TOTAL HOURS:	8329						

JUNE-AUG DAILY THRU RATE 398 UNITS Tons

FUEL: **NATURAL GAS** SCC: **20100201**
%SULFUR **0.0** %ASH **0.0** BTU/LB-GAL-CUFT **1,030**

SCHEDULE 1 MONTHLY THROUGHTPUTS IN THOUSAND CUBIC FEET

DATE EFFECTIVE:	-	JAN	1196	FEB	831	MAR	939
DATE END:	-	APR	401	MAY	756	JUN	615
DAYS PER WEEK:	-	JUL	1308	AUG	1733	SEP	419
TOTAL DAYS:	-	OCT	248	NOV	512	DEC	863
TOTAL HOURS:	As necessary						

JUNE-AUG DAILY THRU RATE 39.7 UNITS MCF

CHANGES IN FUEL(S) USED, CONTROL DEVICES(S) OR EXHAUST Implemented RACT 05/26/95

ACTUAL EMISSION ESTIMATES (TONS/YR)

PM10	146	CALCULATION METHOD CODE	3
SOX	1318	CALCULATION METHOD CODE	14
NOX	745	CALCULATION METHOD CODE	14
VOC	5.1	CALCULATION METHOD CODE	10
CO	44	CALCULATION METHOD CODE	10

JUNE-AUG (LBS/DAY) FOR EMISSION STATEMENTS: NOX 4056 VOC 28

ZINC CORPORATION OF AMERICA
POTTER TOWNSHIP

TAX ID - PLANT CODE 22-2370906-02
AFS NUMBER 420070032

AIR POLLUTION CONTROL ACT
CERTIFICATION OF DATA ACCURACY
FOR COMPANIES SUBJECT TO EMISSION STATEMENT REGULATION

COMPANY NAME: ZINC CORPORATION OF AMERICA
300 FRANKFORT ROAD
MONACA, PA 15061

I, Thomas W. Johnston, certify under penalty of law as provided in 18 PA C.S. Section 4904 and Section 9(b)(2) of the Air Pollution Control Act, 35 P.S., Section 4009 (b)(2) that I am a company officer or plant manager of the facility identified above, authorized to make this affidavit. I further certify that, based on information and belief formed after this reasonable inquiry, the statements and information contained in this Emission Statement are true, correct, and complete.

(Signature)

Thomas W. Johnston
(Name)

Senior Vice President, Manufacturing
(Title)

February 29, 1996
(Date)

ORIGINAL: 2009
BUSH
COPIES: Smith
Tyrrell
Sandusky
Legal

May 10, 1999

99 MAY 14 PM 1:27

Mr. James Seif
Chairperson, Environmental Quality Board
Rachel Carson State Office Building, 15th Floor
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: Comments on the Draft Rule for Nitrogen Oxides Trading Program [25 PA. Code Chs. 123 and 145]

Dear Chairperson Seif:

Trigen Energy Corporation (Trigen) is pleased to provide comments on the proposed approach of NOx allowance allocation and trading regulations. Trigen has facilities in Philadelphia and is actively developing new projects in the Commonwealth of Pennsylvania. Trigen believes that the Environmental Quality Board (Board) has a rare opportunity to establish a NOx trading program that will encourage efficiency and thus reduce NOx emissions in Pennsylvania, since less fuel will be burned to accomplish the same task. This will result in benefits to the public through improvements in air quality, while promoting a healthy economy by meeting the energy needs of Pennsylvania's residents and businesses. In the following commentary, Trigen outlines three specific recommendations for reworking the proposed NOx Budget Trading Program.

1. Adoption of Energy Efficiency And Renewable Energy Set-Aside Provisions

The proposed rule does not set aside NOx allowances for energy efficiency projects. Trigen believes that the Board is sending the wrong message to the general public if energy efficiency projects are not rewarded. We believe that the Board should take an energy efficiency set-aside approach to NOx allowance allocations. This approach will provide an incentive to energy producers to pursue technologies which improve efficiency and, thereby, reduce NOx emissions. If efficient technologies are not encouraged, this rulemaking will have an adverse effect on the Commonwealth by perpetuating obsolete, high emission energy generation. Currently, many large stationary NOx sources utilize wasteful, outdated technologies that result in at best, perhaps 33% of heat input being converted into useful energy. Electric-only power technologies that convert upwards of 60% of heat input into useful energy are being installed around the country. Combined heat and power production, also called cogeneration, takes energy production to the next level, by squeezing as much as 90% of useful energy out of input fuel. In fact, the U.S. Department of Energy issued a challenge of doubling the U.S. Combined Heat and Power (CHP) capacity by 2010. In early March, U.S. EPA also recognized the energy efficiency value of CHP projects in its guidance document,

"Establishing an Energy Efficiency and Renewable Energy Set-Aside in the NOx Budget Trading Program". U.S. EPA encourages States to set-aside between 5 to 15 percent of the total NOx trading budget to reward energy efficiency and renewable energy projects. Other States have already taken such an approach and more are sure to follow. For example, both New York and Maryland have decided to set aside 3% of their total NOx trading budgets for energy efficiency projects. Trigen encourages the Board to adopt EPA's recommendations and set-aside at least 5% to 10% for energy efficiency and renewable energy projects. A combination of new source and energy efficiency set-asides will stimulate economic growth in the region by attracting new, low-pollution industrial and energy-generating facilities to the Commonwealth. In order to foster this growth and technological progress, it is imperative for Pennsylvania to look toward the future and make provisions for cleaner and better technology.

2. Allocation of Allowances Based on 0.15 lb/MMBtu

The Board requested comments on the approach of using the lower of the EPA model rule emission limitation or any more restrictive allowable emission rate to used in calculating NOx allowances. Specifically, EPA's NOx model trading rule allocates allowances to all sources based on a rate of 0.15 lb/MMBtu. The Board proposed to allocate NOx allowances to budget units based on the lower of either 0.15 lb/MMBtu or the unit's allowable emission rate. Trigen believes the Board would be making a serious error in judgment by failing the follow EPA's recommendation to treat all sources equally. Identical treatment of all sources is essential for an effective cap and trade program and allows market forces (not command and control) to *efficiently* allocate allowances.

In its present form, the proposed rulemaking will result in newer, more efficient sources (e.g., Trigen's Grays Ferry Cogeneration Plant in Philadelphia) subsidizing operations and the finance of emission controls undertaken by less efficient, existing sources. The reasons for this are twofold. First, newer, more efficient facilities can use less fuel to produce the same amount of energy output. Therefore, an input based approach in and of itself is already biased against newer, efficient facilities. These newer facilities, thus, will not only receive fewer allocations simply for burning less fuel, but also for maintaining lower allowable emissions rates. For instance, Trigen's Grays Ferry operation uses an expensive state-of-the-art NOx control technology to control NOx emissions. Trigen has already invested significant capital to achieve the lowest NOx emissions in the industry and ought to be rewarded, not penalized. Grays Ferry, and other highly efficient operations, should receive allowances at a fixed rate of 0.15 lb/MMBtu, and on par with all other facilities, regardless of allowable emissions. It is imperative that the Board exhibit fairness in the initial allocations. The argument is a simple one, and is based on intuitive economics: The more the initial allocation diverges from the most cost-effective allocation, the greater potential for inefficient operations to exercise power over the market. As such, an older, inefficient source can reduce its NOx emissions much more inexpensively than a newer, efficient source, and can, thereby, gain an unfair advantage by accruing additional allowances to use or sell. Utilizing the same

rate to allocate allowances for all sources is the only acceptable and equitable method for distributing allowances. This is consistent with Governor Ridge's petition with EPA to establish a cap and trade program to provide for the most cost effective emission reductions.

3. Prepare For Future Allocations Based On An Output-Based Standard

Trigen steadfastly believes that NOx allowance allocations should be based on total useful energy output rather than the amount of fuel burned. Less efficient units should not receive more NOx allowances simply because they burn more fuel. Massachusetts has developed an output-based allowance allocation system and EPA has been moving toward using output based standards. For example, last year EPA changed the New Source Performance Standards (NSPS) for utility steam generating boilers from heat input-based standards to energy output based standards.

Unfortunately, the regulations as proposed by the Board do not take an output-based approach. Trigen understands that because the Board has to submit the revised SIP to EPA by September 30, 1999, it may not be realistic to develop an output-based NOx allocation system at this time. In the absence of an output-based allocation system, Trigen encourages the Board to begin preparation to adopt an output-based standard following the initial allocation period (i.e., following the 2005 ozone season). In the meantime, an output-based standard workgroup, led by EPA with the active participation of states, industry, and other stakeholders, is in the process of developing guidelines for an output-based NOx allocation system. This guidance document will be available shortly. It is important for the Board to maintain some flexibility in its current rulemaking and allow for, what appears to be, an inevitable move toward an output-based approach in the future.

Trigen appreciates the opportunity to provide input on these important regulations and is optimistic that our recommendations will be put into practice.

Sincerely,

Trigen Energy Corporation

Jim Qin, PhD, P.E.
Manager, EHS Programs

Cc: Herman Schopman, Vice-President, Trigen-Philadelphia
Steve Smith, President, Trigen-Philadelphia
Steve Lomax, EHS Analyst, Trigen-Energy Corporation
Mark Hall, Director of Government Affairs, Trigen-Energy Corporation

May 10, 1999 (submitted via e-mail)

Mr. James Seif
Chairperson, Environmental Quality Board
Re: Summary of Comments on the Draft Rule for Nitrogen Oxides Trading Program

Dear Chairperson Seif:

Trigen Energy Corporation (Trigen) is pleased to provide this one-page summary of our detailed comments on the proposed NOx allowance allocation and trading regulations. Trigen has facilities in Philadelphia and is developing new projects in the Commonwealth of Pennsylvania. Trigen believes that the Environmental Quality Board (Board) has a rare opportunity to establish a NOx trading program that will encourage *efficiency* and thus reduce NOx emissions. Trigen outlines three recommendations for reworking the proposed NOx Budget Trading Program.

1. Adoption of Energy Efficiency And Renewable Energy Set-Aside Provisions
The proposed rule does not set aside NOx allowances for energy efficiency projects. Trigen believes that the Board is sending the wrong message to the general public if energy efficiency projects are not rewarded. This approach will provide an incentive to energy producers to pursue technologies which improve efficiency and, thereby, reduce NOx emissions. If efficient technologies are not encouraged, this rulemaking will have an adverse effect on the Commonwealth by perpetuating obsolete, high emission energy generation. Currently, many large stationary NOx sources utilize wasteful, outdated technologies that result in at best, perhaps 33% of heat input being converted into useful energy. Electric-only power technologies that convert upwards of 60% of heat input into useful energy are being installed around the country. Combined heat and power production (or, cogeneration) squeezes as much as 90% of useful energy out of input fuel. In fact, the U.S. Dept. of Energy issued a challenge to double the U.S. Combined Heat and Power (CHP) capacity by 2010. U.S. EPA encourages States to set-aside 5-15% of the total NOx trading budget to reward energy efficiency and renewable energy projects. Both New York and Maryland have set aside 3% of their total NOx trading budgets for energy efficiency projects. Trigen encourages the Board to adopt EPA's recommendations and set-aside at least 5% to 10% for energy efficiency and renewable energy projects.

2. Allocation of Allowances Based on 0.15 lb/MMBtu
EPA's NOx model trading rule allocates allowances to all sources based on a rate of 0.15 lb/MMBtu. The Board proposed to allocate NOx allowances to budget units based on the lower of either 0.15 lb/MMBtu or the unit's allowable emission rate. Identical treatment of all sources is essential for an effective cap and trade program and allows market forces (not command and control) to *efficiently* allocate allowances. The proposed rulemaking will result in newer, more efficient sources subsidizing operations and the finance of emission controls undertaken by less efficient, existing sources. Newer, more efficient facilities can use less fuel to produce the same amount of energy output. Therefore, an input based approach, in and of itself, is biased against newer, efficient facilities. These newer facilities will not only receive fewer allocations simply for burning less fuel, but also for maintaining lower allowable emissions rates. For instance, Trigen's Grays Ferry operation uses state-of-the-art NOx control technology. Trigen has already invested significant capital to achieve the lowest NOx emissions in the industry and ought to be rewarded, not penalized. Grays Ferry, and other highly efficient operations, should receive allowances at a fixed rate of 0.15 lb/MMBtu, and on par with all other facilities, regardless of allowable emissions. The argument is a simple one, and is based on intuitive economics: The more the initial allocation diverges from the most cost-effective allocation, the greater potential for inefficient operations to exercise power over the market. As such, an older, inefficient source can reduce its NOx emissions much more inexpensively than a newer, efficient source, and can, thereby, gain an unfair advantage by accruing additional allowances to use or sell. Utilizing the same rate to allocate allowances for all sources is the only acceptable and equitable method for distributing allowances.

3. Prepare For Future Allocations Based On An Output-Based Standard
Trigen believes that NOx allowance allocations should be based on total useful energy output rather than the amount of fuel burned. Less efficient units should not receive more NOx allowances simply because they burn more fuel. Massachusetts developed an output-based allowance allocation system and EPA is now promoting output based standards. Trigen encourages the Board to to adopt an output-based standard following the initial allocation period and to maintain flexibility in its current rulemaking to allow for an inevitable move toward an output-based approach.

Sincerely,
Trigen Energy Corporation, c/o Jim Qin, PhD, P.E., Manager, EHS Programs

Statement on Behalf of Allegheny Power Presented at the April 6, 1999 Public Hearing on the Pennsylvania Environmental Quality Board's Proposed Rulemaking on Interstate Ozone Transport Reduction

Good afternoon, I am Jim Murphy, Air Quality Manager for Allegheny Power. My comments regard the Environmental Quality Board's proposed rulemaking on interstate ozone transport reduction (Title 25 PA Code Chapter 145) that was published in the Pennsylvania Bulletin on March 6, 1999. Allegheny Power provides electricity to and serves an area of about 29,100 square miles and 1.3 million customers in portions of five states -- Maryland, Ohio, Pennsylvania, Virginia, and West Virginia. Allegheny Power has a total power generation capability of over 8,000 MW, of which over 2,300 MW is provided by coal-fired power stations located in Pennsylvania which would be subject to this proposed rulemaking.

Since testimony is limited to ten minutes, I will limit my oral comments to the following major areas of concern:

1. Implementation of the final regulation should be contingent on the outcome of current litigation challenging the legality of the EPA's NOx SIP call on which this proposed regulation is based.
2. This rulemaking should be re-proposed upon revision of affected source sectors and emission reduction obligations.
3. Distribution of NOx allowances from the compliance supplement pool should be based on banked allowances generated under Chapter 123. (EQB Question No. 1)
4. The emission rate used to calculate the NOx allowance allocations for EGU sources should be equal to 0.15 lb./mmBtu or allowable emission level, whichever is lower. (EQB Question No. 2)
5. The electric generating unit NOx budget needs to be revised to include the sources less than 25 MW that are affected sources under the proposed rule. (EQB Question No. 3)
6. Provisions for a NOx allocation set aside for new sources should be reduced.

However, in my written testimony I have also included additional comments on the details of the proposed NOx allocation methodology for electric generating units (EGU) that I will not cover today in my oral comments.

Implementation of final regulation should be contingent on the outcome of current litigation challenging the legality of the EPA's NOx SIP call.

The sole purpose of the proposed rulemaking is to respond to the NOx SIP Call regulation published by the U.S. Environmental Protection Agency on October 27, 1998. Allegheny Power, along with numerous utilities, industrial groups, and affected States do not believe the EPA provided sufficient technical justification to support the NOx SIP call's stringent, one-size-fits-all reduction requirements. Additionally, there are questions concerning the EPA's legal authority to issue the SIP call. As a result, the EPA's SIP call regulation is the subject of a legal challenge (Michigan, et al v. EPA, Case No. 98-1497 and consolidated cases,

D.C. Circuit). Consequently, some or all of the SIP call could be invalidated or revised. The current briefing schedule for this litigation should provide for a final decision by the end of this year. Unfortunately, Pennsylvania's proposed rulemaking is likely to be finalized prior to a decision on the litigation. Therefore, Allegheny Power recommends the Pennsylvania Department of Environmental Protection (Department) include language in the final rulemaking that would revoke implementation of the rule subject to the outcome of the litigation. Otherwise, affected Pennsylvania sources would be subject to a rule without any regulatory or legislative authority.

This rulemaking should be re-proposed upon revision of affected source sectors and emission reduction obligations.

We support the Department's overall approach to include the same source sectors and associated emission reduction obligations as were proposed in the EPA's NOx SIP Call rulemaking. However, should the Department decide to revise either the source sector budgets or emission reduction obligations contained in this proposed rulemaking, we request that the rule be re-proposed for additional public comment prior to final adoption. Our concern is that a relaxation of control requirements on one source sector would have the affect of increasing the stringency of control on other source sectors in order for Pennsylvania to maintain it's overall NOx budget obligation under the SIP call.

Distribution of NOx allowances from the compliance supplement pool should be based on banked allowances generated under Chapter 123. (EQB Question No. 1)

We support the Departments proposed methodology to issue early reduction credit allowances out of the State's compliance supplement pool for sources subject to existing Chapter 123 requirements (OTC Phase II). Under proposed Section 145.55.(c)(9), the NOx allowances banked under existing Section 123.110 for years 2000 through 2002 shall be considered early reduction credits eligible for an allocation distribution from the compliance supplement pool. Since affected sources begin compliance with Chapter 123 beginning in May 1999, Allegheny Power recommends that NOx reductions made in 1999 also be eligible for the award of early reduction credits under this proposed rule. We also suggest the following clarifications to section (c)(9) may be necessary:

1. The number of "banked" allowances should be based on the difference between the sources Chapter 123 Appendix A allocation and their actual emissions. This prevents any early reduction credits being based on a previous control periods carryover banked allowances, or traded allowances.
2. The number of "banked" allowances should be based on a source's cumulative calculation for the entire 2000 through 2002 period. Otherwise, "banked" allowances from one control period could be used to cover higher emissions in a subsequent control period, and still be eligible as early reduction credits. (Note: It will also be necessary to revise the early reduction credit request due date contained in proposed Section 145.55.(c)(4)(ii) to allow all requests be submitted by October 31, 2002 rather than October 31 of the year in which the early reductions are made.)

Emission rates used to calculate the NOx allowance allocations for EGU sources should be equal to 0.15 lb./mmBtu or allowable emission level, whichever is lower. (EQB Question No. 2)

We support the Department's proposed methodology to use the lower of 0.15 lb./mmBtu or allowable emission level to calculate the NOx allowance allocation for electric generating unit sources contained in Section 145.42.(b)(1). New sources that enter the program are likely to have permitted emission rates that are substantially lower than 0.15 lb./mmBtu. There is no policy justification for these new sources to be given an allocation in excess of their operational requirements. To do otherwise would amount to requiring the existing affected sources in the NOx budget trading program to provide an economic subsidy for the construction and operation of the new source. Since there is an overall State NOx emissions cap, there is certainly no environmental benefit in the award of unneeded NOx allowances to a new source at the expense of the existing sources.

The electric generating unit NOx budget needs to be revised to include the sources less than 25 MW that are affected sources under the proposed rule. (EQB Question No. 3)

Allegheny Power is indifferent whether the lower cut-off for EGU sources is less than 25 MW as proposed by the EPA NOx SIP call, or 15 MW as proposed by the Department in this rulemaking. However, the electric generating unit NOx budget needs to be revised to include the sources less than 25 MW that are affected sources under the proposed rule.

NOx allocation set aside for new sources should be reduced.

In Section 145.42.(d) the Department has proposed a new source NOx allocation set aside equal to 5% of the state budgets for both the electric generating units budget and the non-electric generating units budget during the initial 2003-2005 control periods and 2% for all subsequent control periods. We do not believe it is necessary to establish such a large set aside for new electric generating units. A reduction in the size of the new source set-aside suggested by the EPA and proposed by the Department can be substantiated due in part to the Department's proposal to base the sources NOx allocation on the lower of 0.15 lb./mmBtu or the sources permitted emission rate. It is unlikely any new EGU source would be permitted at a rate greater than 0.10 lb./mmBtu. As a result, a smaller new source set-aside pool would adequately support the same amount of new source generation. Therefore, Allegheny Power recommends the Department reduce the size of the new source set-aside pool to 3% for the initial 2003-05 allocation period and 1% for all subsequent control periods.

Additional written comments not presented with oral testimony:

Section 145.41. Timing requirements for NOx allowance allocations.

The Department has proposed an initial three-year allocation period of 2003-2005 followed by single-year allocations thereafter that would be issued three years prior to the corresponding control period. Allegheny Power supports these timing requirements for NOx allowance allocations.

Section 145.42.(a) Heat input used for calculating NOx allowance allocations.

We support the Department's proposed methodology to use the average of the two highest amounts of the unit's heat input for the control periods in 1995, 1996, and 1997 for calculating the NOx allowance allocations for the initial 2003-05 allocation period. However, we do not support the Department's proposed methodology to use the unit's heat input from the single control period in the year that is four years before the year of subsequent allocation periods beginning 2006 and thereafter. For instance, heat input for 2002 would be used to calculate the 2006 allocation. Instead, we recommend the Department to use the average of the two highest amounts of the unit's heat input for the three control periods that begin six years before the year of subsequent allocation periods. For example, the unit's heat inputs for the control periods in 2000, 2001, and 2002 would be used to calculate the 2006 allocation. This proposed method is obviously similar to that proposed by the Department for the initial 2003-05 allocation period. The advantage of using the average of the two highest of a three-year baseline control period, as opposed to a single year baseline control period, is to more accurately reflect normal utilization of a unit. The two-out-of-three period method would prevent an abnormal single period utilization, either high or low, from skewing the future period allocation. Since the three years of baseline period heat input data is already available to the Department, the two-out-three period method is no more difficult to implement than the single period method. Such a revision is well within the SIP approvability guidelines contained in the EPA's NOx SIP call rule.

Allegheny Power appreciates the opportunity to comment on this proposed rule and plans to submit more extensive written comments by the May 10, 1999 deadline. For further information please contact:

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Procter&Gamble

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May 6, 1999

Environmental Quality Board
15th Floor, Rachel Carson State Office Building
P.O. Box 8477
400 Market Street
Harrisburg, PA 17105-8477

Dear Sir or Madam,

Outlined below please find comments submitted on behalf of the Procter and Gamble Paper Products Company on the Environmental Quality Board's proposed rulemaking concerning Interstate Ozone Transport Reduction, 25 PA Code Chapters 123 and 145. As proposed, the regulations would have a significant effect on our facility, and we are pleased to have the opportunity to comment on the rulemaking.

We support the Board's general approach to achieving the federal State Implementation Plan (SIP)-required regional NOx reductions via a flexible "cap and trade" program which should provide for emissions reductions at the least possible cost. We also encourage the Board to pursue steps to minimize to the greatest extent possible any administrative changes (permitting, monitoring program approval, etc.) required for existing NOx Budget program-affected sources to comply with the proposed rule.

Our specific comments on the proposed rulemaking are as follows:

Emission Monitoring Requirements

In the preamble to the proposed rulemaking, the Board has stated that the monitoring requirements included in Sections 145.70 - 145.76 are generally consistent with the provisions of the existing NOx budget rule. The monitoring requirements in the Department's current regulations at Chapter 123 reference the procedures contained in the Guidance for Implementation of Emission Monitoring Requirements for the NOx Budget Program ("OTC Monitoring Guidance"). The provisions in the current proposed rulemaking mirror those included in the EPA model rule, and refer specifically to requirements outlined at 40CFR Part 75. There are a number of significant differences between the OTC Monitoring Guidance document and the Part 75 requirements, including more restrictive system relative accuracy requirements, additional monitoring requirements for units exhausting to multiple stacks, and additional bias factors for small emission units using default emission factors. Use of the proposed Part 75 monitoring requirements will impose additional monitoring and compliance costs on primarily smaller (non-Part 75) emission sources. Many of these affected facilities have recently completed modifications to continuous emission monitoring (CEM) systems to comply with the OTC Monitoring Guidance for the current NOx budget program. The OTC

Monitoring Guidance was developed in partnership with US EPA to insure these facilities accurately accounted for emissions in a cap and trade program virtually identical to that included in the Board's current proposed rulemaking. As the regulations are proposed many affected sources will likely be required to again modify their CEM systems, with no significant environmental or emissions trading program quality gain. We would encourage the Board to include reference to the existing NOx OTC Monitoring Guidance document in the Chapter 145 regulation, and to permit existing approved and certified NOx Budget Program emissions monitoring systems to continue to operate as approved monitoring systems under this current regulation.

Allowance Banking

The Board has requested comment on whether to allow the use of banked allowances from the existing NOx Budget Program in the years 2003-2004 under the new proposed rule. We support allowing the full use of excess allowances generated and banked during 1999-2002 under the future program, as this will provide additional certainty to the allowance trading system, will aid in achieving the required NOx reductions in the most cost effective manner possible, and may encourage greater early emission reductions. Further, the flow control provisions included in the proposed rulemaking provide insurance that excess NOx emissions in any one ozone season are prevented. We recommend that the Board enable the full use of allowances generated under the current NOx Budget Program for use in any year following the implementation of Chapter 145 SIP call regulations, subject to the flow control provisions included in the proposed rule.

Small (< 25MW) Electrical Generating Units

The Board has further requested comment as to whether Pennsylvania's SIP call NOx control regulation should include sources connected to electric generating units of 15MW or greater capacity, rather than follow the EPA model rule level of 25MW as a cut off for regulation. EPA's analysis in the development of the SIP call model rule indicated that controlling emissions of sources below 25 MW to the level envisioned in the rule (i.e. 0.15 pounds NOx/mmBTU) would not be highly cost effective, and that control of emissions from these sources would have a minimal effect in improving regional air quality. Given the relatively large number of these smaller sources and the low total NOx emissions from these sources, we would encourage the Board to modify the proposed regulation and include only those electrical generating unit (EGU) sources of greater than or equal to 25 MW. Further, consistent with previous federal regulatory actions, we would encourage the Board to regulate as EGUs only those units with significant net sales of electricity to minimize regulatory impact on smaller, energy efficient industrial cogeneration facilities.

Allowance Allocation

The Board has proposed at Section 145.42 that initial allowances from non-EGU affected units be established based on 1995 actual heat input, while initial allowance allocation for EGU affected units would be based on the average of the two highest years' heat input during the period 1995 - 1997. Non-EGU industrial sources may face similar variability in year to year utilization and heat input as EGU units. We would recommend that the

Board modify the regulation to use the same methodology (average of the highest two years) to allocate initial allowances for both EGU and non-EGU sources.

Internal Combustion Engines

The Board has proposed to exempt large emergency standby electrical generation units with limited annual operating hours from the provisions of this rulemaking. We would encourage the Board to extend this exemption to other (non-electrical generation) emergency standby internal combustion engines with a similar restriction on operating hours. As these units would be expected to be infrequently used and have a very small contribution to regional NOx emissions, the cost for controlling and monitoring emissions from these sources would not appear to be justified.

We appreciate the opportunity to offer comment on this important proposed rulemaking. Please feel free to contact me with any questions on our comments.

Sincerely,

J. Andrew Hadley

J. Andrew Hadley, P.E.
Site Environmental Manager

Environmental Affairs Division

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May 6, 1999

Environmental Quality Board
15th Floor
Rachel Carson State Office Building
P.O. Box 8477
Harrisburg, PA 17105-8477

Re: EQB Proposed Interstate Ozone Transport Reduction Regulation
29 Pa.B. 1319-1349, March 6, 1999

Attached please find PECO Energy Company's comments on the above referenced proposed regulation. These comments expand upon the points we raised in our April 8, 1999 public testimony comments and also cover several new areas.

For your background, PECO Energy Company owns approximately 9,200 megawatts of electric generation capacity which is located primarily in southeastern Pennsylvania. PECO Energy operated generation typically produces over 20% of the ozone season electric generation in Pennsylvania (monthly data available from EIA Form 759). Despite PECO Energy's large contribution to the Commonwealth's summertime electric output, the Company's "contribution" to the state's total electric generation NOx emissions is in the area of 5% per ozone season. This very favorable ratio of NOx emissions to electric output is due primarily to PECO Energy's use of zero-emission nuclear generation, and already relatively low emission rate fossil generation.

For additional perspective, the 1998 Natural Resources Defense Council U.S. electric generation "Benchmarking Report" indicates that PECO Energy's 1996 total NOx emission rate was approximately 1.1 pounds of NOx per megawatt hour. This is 163% lower than the Pennsylvania average NOx emission rate of 2.9 pounds of NOx per megawatt hour. These statistics are on a "total" output basis. That is, electric generation from all sources, for all Pennsylvania companies, is factored into the NRDC statistics.

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PECO Energy is one of only a handful of electric generators that publicly supported the general need for the NOx SIP Call regulation during EPA's regulatory development process over the past two years. Our support is based on a belief that a uniform NOx reduction requirement, over a broad geographic area, with the same implementation date, provides the most cost-effective, competitively neutral, and environmentally effective method to support attainment of the national ozone standard in the eastern United States.

While we support the general approach of the NOx SIP Call, we nonetheless have a number of requested changes to the Pennsylvania implementing regulations which are of significant importance to our Company. Our specific comments are organized as follows:

I. NOx Allocation Methodology Issues

II. Compliance Supplement Pool Use

III. Applicability Level 15 MW vs. 25 MW

IV. Emergency Diesel Generator Exemption

V. Monitoring

VI. Other Issues

We appreciate the opportunity to provide comments to the EQB on this proposed regulation. We would also like to thank Pennsylvania DEP at this time for their leadership role in supporting a NOx reduction program that includes states to the south and west of Pennsylvania which contribute significantly to the Commonwealth's nonattainment problems. This program will play a significant role in helping to reduce one-hour and eight-hour ozone nonattainment in a manner which creates a more level playing field for Pennsylvania's electric generators versus the current Ozone Transport Region program.

Please feel free to contact us if you would like any additional information regarding the points raised in these comments.

Sincerely,

David J. Cesareo

David J. Cesareo
Director, Environmental Affairs

PECO Energy Comments:
EQB Interstate Ozone Transport Reduction Proposed Rule
(29 Pa.B. 1319-1349)

I. NOx Allocation Methodology Issues

⇒ Multiple Year Baselines are Better:

With regard to the initial control period, PECO Energy supports EPA's model rule method of basing each EGU unit's allocation on the average of its two highest heat input years between 1995 and 1997. Multiple year baseline averages are critical to minimize the distortions that can arise from allocations based on a unit's operations during any single historic year. For example, if a unit had an unexpected forced outage in a single baseline year, future year allocation(s) could be incorrectly calculated based upon a one-time, anomalous utilization level in the baseline year. For the same reason, we ask that DEP also consider modifying EPA's model rule for subsequent control periods to utilize the same multiple year baseline concept in calculating future control period allocations.

⇒ Allocation Periods Should be Longer:

With regard to §145.41, we believe that allocations should be made in a minimum of three year blocks to support long-term planning and lower compliance costs. Five year blocks would be most appropriate in that they provide a reasonable period of certainty for planning purposes but still offer periodic opportunities to adjust unit allocations to reflect new units or significant changes in unit utilization.

⇒ For First Allocation Block, Allocation Method Should be Consistent with the EPA Model Rule

With regard to §145.42(b)(1), PECO Energy supports allocations for the first allocation block based on the EPA model rule method. From our perspective, a level playing field is achieved during the first allocation block by the EPA model rule with respect to its uniform application of 0.15 lb/mmBtu to all EGU units. Modifying this approach to make it a conditional "lesser of 0.15 or allowable," as currently proposed, runs counter to the development of a level playing field for electric generators which we believe is important from an equity and market perspective.

The allocation of allowances will directly affect compliance decisions and specifically, decisions to install controls such as SCR on units where it is most cost-effective to over comply. Any excess allowances created from the installation of controls could be sold into the market to those who do not have low cost compliance options on their units. The result is a reduced overall cost of compliance for both those who install controls and those who do not have low cost control alternatives. A uniform allocation rate for all sources rewards those that have already invested to over comply and provides the appropriate incentive to the highest emitting sources to install technology to over control and prime the market.

⇒ **Unused New Source Set Aside Allowances Should be Returned to Existing Sources:**

We support the provisions in the proposed regulation to return the unused portion of the new source set aside to baseline sources as per § 145.42(f).

⇒ **Output Based, Generation Neutral Allocation Method Should be Basis for Future Allocations:**

PECO Energy commented during the NOx SIP Call development process that we believe NOx allocations based on megawatt hours of output from all forms of generation provides the greatest incentive to increase the use of low, and zero, emissions generation. Given that Pennsylvania's implementing regulations are due to EPA by October 1999, we understand that DEP will not have enough time to work through some of the unresolved issues surrounding output based, generation neutral allocations.

We ask, however, that DEP consider this option as a basis for determining NOx allocations for control periods after the initial allocation period. For example, the regulations could base the initial 3 or 5 year control period allocations on the existing 2 of 3 year average 1995-97 heat input method, but provide for a revisit in several years of the subsequent allocation periods' allocation method to consider future EPA guidance. EPA has promised such guidance in its preamble to the final SIP Call regulation. Specifically, EPA plans to further investigate how output based systems could be used "by states as part of their trading program rules in their SIPs and by EPA in future allocations to States." [63 FR 57409]

We suggest this alternative output based approach since we believe it provides an incentive to use the lowest emission generation possible and to install the most cost-effective controls to lower overall cost of compliance under a market-based trading system. For example, inefficient, high emission rate sources would receive fewer allowances under an output based system. These are the units that have the best opportunity to install controls at the lowest dollar per ton removal rates to support the lowest cost regional program possible. If they receive larger allocations based on heat input, in contrast, they are less likely to install the most cost-effective controls. Also, there are other air quality co-benefits to output based systems such as reduced carbon dioxide, sulfur dioxide and mercury emissions which result from the use of less fossil fuel per mWh of generation output.

II. Compliance Supplement Pool Use

The EQB requests specific comment on the use of the 13,716 ton compliance supplement pool. EPA's final SIP Call allows states to utilize the compliance supplement pool for a number of purposes, including early banking of NOx reductions, transfer of OTC banked allowances, or to provide relief to those who can demonstrate that they can not comply by May 1, 2003.

Our major concern with the distribution of the compliance supplement pool is that it not perpetuate allocation distortions from the 1999-2002 OTC program into the new SIP Call program. For example, the SIP Call requires a uniform emission reduction from an average of recent baseline years.

The OTC program, on the other hand, makes allocations based on a non-uniform reduction requirement from a single baseline year that will be over 10 years old at the time of the "early banking". The non-uniformity of the OTC allocation methodology therefore means that those having to do the least under the OTC program would have the greatest chance of banking early tons. We do not believe that this is an appropriate option from an environmental, equity or economic perspective.

Rather than perpetuate the inequities of the OTC program into the new regulation, we suggest that the regulation explicitly allocate the compliance supplement pool on a pro rata basis. Specifically, we suggest that DEP utilize recent year ozone season megawatt hour data from EIA Form 759 to divide the compliance supplement pool among all companies based upon their total megawatt hours from all forms of electric generation.

Alternatively, a pro rata distribution based on heat input from the 1995-1997 baseline years could be utilized. Should DEP determine to keep its current language regarding the transfer of allowances from the OTC program to the NOx SIP Call program, we ask that banked allowances under the OTC program all be treated the same. That is, that there be no prejudice regarding whether or not the banked allowances were "created" in Pennsylvania. Such prejudice would be inconsistent with the intent of both the OTC and EPA programs to get the most cost effective tons out of the air on a regional basis.

III. Applicability Level 15 MW vs. 25 MW

EPA's SIP Call sets an applicability level of 25 megawatts for electric generation units in the 22 eastern states. While we understand that the OTC program set a lower applicability level of 15 megawatts, we urge DEP to remain consistent (with regard to its § 145.4 Applicability definition) with the federal model rule.

PECO Energy currently operates ten combustion turbines (CTs) rated between 15 and 25 megawatts (all are 15MW). These ten CTs are all already permit constrained to a 5% annual capacity factor as part of their NOx RACT permits. During the 1998 ozone season, average emissions per combustion turbine in this category were about 8.5 tons of NOx (85 tons total). Within the general context of electric generation units, these are very small, infrequently operated sources. They are also negligible within the context of the daily southeastern Pennsylvania NOx inventory which was identified as 451 tons of NOx per summer day (or roughly 69,003 tons per ozone season) in the Southeastern Pennsylvania Ozone Stakeholder Working Group final report. This translates to PECO Energy's ten 15 MW CTs equaling about 1/10th of 1% of the southeast PA ozone season NOx inventory.

While these are small emission sources, they require a disproportionately large effort to manage under the current and proposed stationary source NOx reduction programs. For example, fuel consumption during hours of operation must be closely monitored to develop NOx emissions data. This data must be "manually" collected by employees who must go to the physical location of the CTs on a daily basis when they are operating. Since the CTs are in multiple locations throughout the service territory, this is a labor intensive process.

During its April 23, 1999 meeting, DEP's Air Quality Technical Advisory Committee (AQTAC) voted unanimously (with one abstention) to recommend that DEP remain consistent with the federal program and set the applicability level at 25 megawatts.

We believe this approach would also be very helpful to DEP in terms of removing the potentially contentious issue of obtaining NOx allowances for units below 25 megawatts since EPA did not include them in its EGU budget baseline. Should DEP determine that 15-25MW CTs must participate in the program, we strongly urge that DEP work with EPA to increase the Pennsylvania EGU budget so that allocations can be made to these sources without impacting other units' allocations. Again, however, we believe remaining consistent with the federal 25 MW applicability level is the best alternative.

IV. Emergency Diesel Generator Exemption

We appreciate DEP including draft emergency diesel generator (EDG) exemption language in its proposed *Subchapter B: Emissions of NOx From Stationary Reciprocating Internal Combustion Engines.* We strongly recommend, however, that §145.101(d) be revised to base the exemption solely upon operating hours per <u>each</u> EDG.

While the current DEP language also uses operating hours, it also includes what we believe is an overly narrow description of only one of a number of potential operating scenarios for an electric utility industry EDG. This narrow description could effectively make the exemption unattainable. For example, the current proposed exemption does not seem to allow for periodic reliability testing or activation of an EDG in <u>anticipation</u> of a potential loss of power to the generating plant which it serves. With regard to EDGs located at fossil power plants, there may also be brief periods of time during which an EDG may directly, or indirectly by replacing auxiliary boiler load, supply electric to the grid to help prevent a local or regional power grid failure. Such operation of an EDG would generally take place at the direction of PJM during a PJM Max Emergency situation.

To allow reasonable flexibility in the use of EDGs to meet normal electric utility industry operating needs, we suggest that the definition at §145.101(d) be revised to read:

> *(d) A diesel generator which has a permit limitation of a maximum cumulative operation of 208 hours per control period is exempt from the requirements of this subchapter.*

While we believe it is clear in the above suggested exemption language, we ask that the DEP make clear in its final regulations, either in the regulations or the preamble, that the 208 hours per control period applies to each EDG individually, even if more than one EDG is located at the same generating facility.

We have also suggested the use of the phrase "diesel generator," rather than the current proposed language ("emergency standby electric generation units") since there may be other permitted industries for which this exemption should be available.

Following is additional discussion which describes some of PECO Energy's specific operation of EDGs, as well as general industry considerations, which support our request.

PECO Energy utilizes 15 emergency diesel generators (EDGs) on its system. All are rated between one and 3.75 MW which is typical for the electric utility industry. Twelve of these are associated with the Company's Limerick and Peach Bottom nuclear power plants. The aggregate typical actual NOx emissions of all 15 of our EDGs is about 14 tons per ozone season (5/12 times annual typical actual of 35 tons). These emissions result primarily from brief, periodic reliability testing which may consist of weekly or monthly operation of the EDG for a period of one, or several, hours.

We estimate that further controlling NOx emissions from PECO Energy EDGs would cost 10s of thousands of dollars per ton removed. Costs would be double or triple for EDGs at nuclear power plants (where the majority of PECO Energy's EDGs are located) due to rigorous Nuclear Regulatory Commission (NRC) quality and testing requirements. (see 10 CFR 50, Appendix B) These NRC requirements could easily result in capital costs in the area of $1 million per EDG. This would be a rather ironic requirement given that PECO Energy nuclear generation displaces over 4,400 megawatts of fossil generation. We estimate that, on an annual basis, PECO Energy nuclear generation avoids about 80,000 tons of NOx (roughly 30,000 ozone season tons) versus what would be the case if the same number of megawatt hours was generated at the 1996 Pennsylvania average NOx emission rate for fossil generation.

Nuclear plant EDGs have historically been exempted from the EPA's emission regulations. The following is quoted from the Federal Register notice for implementing 40 CFR Part 60:

> Emergency standby engines also require special consideration. These engines operate less than 200 hours per year under all but very unusual circumstances. Consequently, they add relatively little to regional or national total NOx emissions. The largest category of emergency standby units is for nuclear power plants, where these engines provide power for the pumps used for cooling the reactors. These engines must attain a set speed in ten seconds and must assume full rated load in 30 seconds. In some cases, application of the demonstrated NOx control technique limits the responsiveness of these engines in emergency situations. Therefore, all emergency standby engines are exempted from standards of performance. [FR Vol. 44, No. 142, Page 43156, July 23, 1979].

As the above quote suggests, rapid, reliable EDG performance at nuclear power plants is of paramount importance from a safety and sound operating perspective. The inability to comply via emission allowance purchase under Subchapter B (as an option to comply without impacting EDG performance) is another reason why it is critical that PECO Energy's requested exemption be incorporated into the final regulations.

It should be noted that with regard to EDGs located at nuclear power plants that the Nuclear Regulatory Commission prohibits operation of EDGs for peaking purposes and for other purposes not related to their function of providing standby power when needed. This is due to the loss of redundancy that would occur if the EDGs were connected to the offsite power network. A discussion of this issue can be found in the NRC's Standard Review Plan (SRP) 8.1, Branch Technical Position ICSB - 8 (PSB) "Use of Diesel Generator Sets for Peaking", in the context of an interpretation of General Design Criteria 17 of 10CFR50, Appendix A.

Finally, with regard to subchapter B, we ask that in the definition of Higher Heat Value in § 145.102, that the years of issue or reaffirmation on the cited ASTM standards should be omitted. ASTM periodically reviews and updates their standards as technology improves. Locking in a specific year of issue would prevent companies from taking advantage of advancements in the "state-of-the-art" without having to make a change to DEP's NOx SIP Call regulations. The NRC, for example, has recently dropped the year-of-issue matter from their Standard Technical Specifications for EDG fuel oil; instead, they simply regulate at the level which cites the standard by number.

V. Monitoring

An ad hoc committee of the Air Quality Technical Advisory Committee (AQTAC) was formed earlier this year to compare and contrast the monitoring and reporting provisions of the 110 SIP Call versus the current Chapter 123 program. This ad hoc committee found that in some areas the 110 SIP Call provisions were more burdensome than the current Chapter 123 requirements. We support utilizing the current Chapter 123 program in place of the 110 SIP Call requirements. We understand that there are issues associated with this which must be worked out with EPA to ensure that interstate trading will not be restricted if Pennsylvania chooses to use the current Chapter 123 monitoring regime. We believe that the AQTAC's suggestion to DEP that it work with the OTC states and EPA on this approach to allow Pennsylvania to continue using the Chapter 123 program in lieu of the proposed Chapter 145 monitoring program is a good one.

VI. Other Issues

⇒ Pennsylvania's Regulations Should be Consistent with EPA's Unit Classification Methodology

In determining state budgets under its NOx SIP Call regulation, EPA utilized a specific methodology to determine unit classification (EGU or non-EGU). In a December 24, 1998 Federal Register notice (63 FR 71220), EPA further clarified this methodology and stated that it "will continue to use this methodology to classify units that operated on or before December 31, 1995 as EGUs or non-EGUs ... However, EPA may reconsider unit classifications in 2007 along with the 2007 transport reassessment." PECO Energy believes that a situation may exist in Pennsylvania's proposed regulations which could inadvertently create a conflict between EPA's classification methodology and the "classification" of units under Pennsylvania's proposed program. For example, cogeneration units which provide steam to industrial processes could, in some cases, "look" like an EGU under Pennsylvania's proposed regulation even though they have been deemed non-EGU units under the EPA classification methodology.

We ask that the Department clarify its regulations, to the extent necessary, to ensure that cogeneration units deemed by EPA to be non-EGUs are not negatively impacted by the Department's final regulations. Such a clarification would be consistent with the general interest of the AQTAC over its last several meetings to recommend removal of inadvertent disincentives to positive environmental and economic actions (e.g. recent repowering discussions). Since cogeneration represents a more efficient form of energy production, its support would be consistent with the recent interests of AQTAC members.

For reference, the next two pages of this document contains the bulk of EPA's discussion at 63 FR 71223 with regard to determining whether or not a unit is an EGU:

Clarification of EGU Classification for Purposes of Estimating Budget Reductions

The following discussion clarifies EPA's classification of units as EGUs. This clarification also applies to the proposed FIP and the EPA action under section 126.

Consistent with the supplemental notice of proposed rulemaking (63 FR 25902, May 11, 1998) and the accompanying technical support document related to budget development, EPA took a two-step approach to determining which of the following categories a boiler or turbine fit into: large EGU, small EGU, large non-EGU or small non-EGU. First, EPA determined if a boiler or turbine fit into the category of EGU or non-EGU. The EPA then determined if the boiler should be classified as large or small.

The EPA used three sources of data for determining if a generator's purpose included generation of electricity for sale and thus qualified the unit connected to the generator as an EGU. First, EPA treated as EGUs all units that are currently reporting under Title IV of the Clean Air Act. Second, EPA included as EGUs any additional units that were serving generators reporting to the Energy Information Administration (EIA) using Form 860 in 1995. Form 860 is submitted for utility generators. Third, EPA included units serving generators that reported to EIA using Form 867 in 1995. Since Form 867 is submitted by non-utility generators, including generators "which consume all of their generation at the facility," EPA excluded any units for which EPA had information indicating that the unit was not connected to any generators that sold any electricity. This was primarily determined by excluding units that were not listed as sources that sell power under contract to the electric grid using the electric generation forecasts of the North American Electric Reliability Council.

Once EPA determined that a boiler or turbine should be classified as an EGU, EPA considered that unit a large EGU if it served a generator greater than 25 MWe and considered it a small EGU if it served a generator less than or equal to 25 MWe.

While EPA believes that this methodology was the best way to classify existing boilers and turbines given the data available, EPA does not believe that this is the best way to classify new boilers or turbines for regulatory purposes. The EPA will continue to use this methodology to classify units that operated on or before December 31, 1995 as EGUs or non-EGUs. Any requests to change the EGU/non-EGU categorization of a unit operating on or before December 31, 1995 that EPA has categorized as an EGU or a non-EGU or any requests to add a unit operating on or before December 31, 1995 that has not been categorized as an EGU or a non-EGU should follow the methodology based on data reported to EPA and EIA, outlined above. Once EPA responds to comments received, EPA does not intend to reclassify units that were in operation before January 1, 1996 because, as discussed below, EPA uses a different approach to classify units that commence operation on or after January 1, 1996. However, EPA may reconsider unit classifications in 2007 along with the 2007 transport reassessment.

The EPA believes there are two important reasons that the methodology outlined above is not appropriate to use on an ongoing basis for new boilers or turbines. First, EPA is concerned about the completeness of data using this methodology. The EPA has this concern because there are limited consequences to not reporting to EIA and because EPA has no assurance that sources will continue to be required to report to EIA using the same forms. Second, because of changes in the electric generation industry and because of regulatory developments such as the SIP call, owners and operators of units may have an incentive to install small (25 MWe or less) generators to larger boilers or turbines that are primarily used for industrial processes and not electricity generation. Such sources should be considered large and be controlled.

For units commencing operation on or after January 1, 1996, EPA plans to use the following two-step process. First, EPA intends to classify as an EGU any boiler or turbine that is connected to a generator greater than 25 MWe from which any electricity is sold. This will be based on information reported directly to the State under the SIP (or EPA in the case of a FIP or section 126 action). The EPA believes this addresses the first concern about completeness of data, as discussed in the previous paragraph. Second, if a boiler or turbine is connected to a generator equal to or less than 25 MWe from which any electricity is sold, it will be considered a small EGU if it has the potential to use more than 50.0 percent of the usable energy from the boiler or turbine to generate electricity. This will address EPA's second concern (discussed in the previous paragraph) about owners or operators of large boilers and turbines that have small generators. All other boilers and turbines (including boilers and turbines connected to generators equal to or less than 25 MWe from which any electricity is sold and which have the potential to use 50.0 percent or less of the usable energy from the boiler or turbine to generate electricity) will be considered non-EGUs and the process described below should be used to classify those units as large or small. Once a unit has been classified, EPA does not intend to reclassify that unit, but may reconsider unit classification in 2007 along with the 2007 transport reassessment. 63 FR 71223

⇒ Avoid "Trigger" Language

We believe that it would be inappropriate for DEP to include "trigger" language in its regulations that would make Pennsylvania implementation of the NOx SIP Call regulations contingent upon implementation of the NOx SIP Call in other states. We believe that such triggers, if broadly adopted by states in the region, could lead to additional implementation uncertainty and a potentially self-fulfilling prophecy of delayed NOx SIP Call implementation and delayed progress towards attainment of the federal ozone standard in the Commonwealth.

However, it would be useful if DEP could include in its final rule preamble a commitment that, should EPA's NOx SIP Call be delayed, that DEP will not seek to impose the OTC Phase III program as a replacement or short-term surrogate for the NOx SIP Call. That is, the current state of science and competitiveness of the electric generation market dictate that uniform NOx controls must take place over the 22 state SIP Call region, on the same time schedule, in order to achieve the needed environmental benefit under a system that provides a level playing field for electric generators in this new era of electric generation competition.

⇒ Surrender Penalties Should Have Flexibility Element to Reduce Impacts to the Allowance Market

Surrender penalties are one of several elements of the proposed regulation which could have the unintended consequence of reducing the availability of NOx allowances to the market. For example, those with potentially surplus NOx allowances may be reluctant, especially in the early years of the program (such as is currently the case with the OTC MOU program) to sell into the market out of a fear that an extreme situation could develop in which they might need the allowances to cover their own current, or future, year emissions, to meet progressive flow requirements, etcetera. This would lead to less market liquidity.

§ 145.54(d) prescribes that unit's not holding sufficient allowances by the end of the annual true-up period must surrender allowances from the next control period in a ratio of 3 to 1. We ask that DEP consider working some flexibility into the surrender requirement similar to that utilized in § 145.54(d)(3)(i) in determining numbers of days of violation. For example, the last sentence in § 145.54(d)(1) could be modified to say " ... equal to three times the number of the unit's excess emissions *unless the owners and operators of the unit demonstrate that a lesser surrender ratio, in no case less than one to one, should be considered.*"

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PECO Energy Company Summary of Comments for the EQB Regarding Its Proposed "Interstate Ozone Transport Reduction" Regulation at 29 Pa.B. 1319

- PECO Energy is generally supportive of the proposed regulation, but does request some modifications to its implementation details as outlined below. Please see our full written comments for complete details on any particular issue.

- **Set Applicability Level at 25MW, Not 15MW.** With regard to §145.4, DEP's Air Quality Technical Advisory Committee (AQTAC) voted during its April 23, 1999 meeting to recommend that DEP remain consistent with the federal program and set the applicability level at 25 megawatts. We support AQTAC's recommendation on this issue.

- **Determining Allocations: Use Multiple Year Averages & Allocate at .15**. With regard to §145.42, PECO Energy supports the use of a multiple year baseline average to calculate emission allocations since averages reduce the impact of unusual operating circumstances that may exist in any given single year. PECO Energy supports the proposed rule's method of basing each EGU unit's 2003-2005 allocation on the average of its two highest heat input years between 1995 and 1997. We ask that this same method of using a two out of three year average also be used for control periods subsequent to 2005, rather than the currently proposed single year approach. We support deletion of the conditional language "or allowable emission level" at §145.42(b)(1) to support a level allocation methodology.

- **Longer Allocation Periods Are Better.** With regard to §145.41, we believe that allocations should be made in a minimum of three year blocks to support long-term planning and lower compliance costs.

- **Allocate Compliance Supplement Pool on Pro Rata Basis.** With regard to §145.55, PECO Energy requests that the compliance supplement pool (13,716 tons) be divided among existing Pennsylvania generators on a pro rata basis based on each unit's share of the 1995-1997 baseline used to calculate initial allocations.

- **Chapter 123 Monitoring Provisions Should be Allowed Under New Program.** Electric generators wishing to use the current Chapter 123 monitoring provisions should be allowed to do so. This issue is currently being reviewed at the AQTAC.

- **Provide Appropriate Emergency Diesel Generator Exemption.** With regard to Subchapter B, we strongly request that low utilization diesel generators be provided with an exemption from the program based simply on an operating hour threshold and that the department not try to define the exact permissible operating purpose for the diesel generator in its exemption language. We suggest the following as a modification of §145.101(d): *"(d) A diesel generator which has a permit limitation of a maximum cumulative operation of 208 hours per control period is exempt from the requirements of this subchapter."*

  PECO's proposed definition will provide the desired environmental protection (e.g. the 208 hour operations cap) while at the same time avoiding the need to prescriptively define (as the current language attempts to do) the exact purpose under which a diesel generator can only be used and still qualify for the exemption. For example, the current proposal does not seem to allow for periodic availability testing of diesel generators. Without an appropriate exemption for low utilization diesel generators, extremely costly control technologies would have to be installed on diesel generators that, in electric utility applications, are typically 1 to 4 megawatts in size, operate at less than a 5% capacity factor, and produce no more than one or two tons of NOx emissions per ozone season. From an economic <u>and</u> environmental perspective, diesel generator emission controls would be a very inefficient use of limited capital dollars.

Original: 2009
Bush
cc: Smith
Tyrrell
Sandusky
Legal

EXHIBITS TO

INTERNATIONAL PAPER COMPANY'S

COMMENTS TO PROPOSED OTR REGULATIONS

federal register

Tuesday
October 27, 1998

Part II

Environmental Protection Agency

40 CFR Parts 51, 72, 75, and 96
Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule

Exhibit A

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 75, and 96

[FRL-6171-2]

RIN 2060-AH10

Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In accordance with the Clean Air Act (CAA), today's action is a final rule to require 22 States and the District of Columbia to submit State implementation plan (SIP) revisions to prohibit specified amounts of emissions of oxides of nitrogen (NO_X)—one of the precursors to ozone (smog) pollution—for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States.

Ground-level ozone has long been recognized, in both clinical and epidemiological research, to affect public health. There is a wide range of ozone-induced health effects, including decreased lung function (primarily in children active outdoors), increased respiratory symptoms (particularly in highly sensitive individuals), increased hospital admissions and emergency room visits for respiratory causes (among children and adults with pre-existing respiratory disease such as asthma), increased inflammation of the lung, and possible long-term damage to the lungs.

In today's action, EPA finds that sources and emitting activities in each of the 22 States and the District of Columbia (23 jurisdictions) emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour and 8-hour ozone national ambient air quality standards (NAAQS), or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States. Further, by today's action, EPA is requiring each of the affected upwind jurisdictions (sometimes referred to as upwind States) to submit SIP revisions prohibiting those amounts of NO_X emissions which significantly contribute to downwind air quality problems. The reduction of those NO_X emissions will bring NO_X emissions in each of those States to within the resulting statewide NO_X emissions budget levels established in today's rule. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. These States will be able to choose any mix of pollution-reduction measures that will achieve the required reductions.

EFFECTIVE DATES: This rule is effective December 28, 1998. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 28, 1998.

ADDRESSES: Dockets containing information relating to this rulemaking (Docket No. A-96-56 and Docket No. A-9-35) are available for public inspection at the Air and Radiation Docket and Information Center (6102), US Environmental Protection Agency, 401 M Street SW, room M-1500, Washington, DC 20460, telephone (202) 260-7548, between 8:00 a.m. and 4:00 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to Kimber S. Scavo, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC 27711, telephone (919) 541-3354; e-mail: scavo.kimber@epa.gov. Please refer to **SUPPLEMENTARY INFORMATION** below for a list of contacts for specific subjects described in today's action.

SUPPLEMENTARY INFORMATION:

Availability of Related Information

Documents related to the Ozone Transport Assessment Group (OTAG) are available on the Agency's Office of Air Quality Planning and Standards' (OAQPS) Technology Transfer Network (TTN) via the web at http://www.epa.gov/ttn/. If assistance is needed in accessing the system, call the help desk at (919) 541-5384 in Research Triangle Park, NC. Documents related to OTAG can be downloaded directly from OTAG's webpage at http://www.epa.gov/ttn/otag/. The OTAG's technical data are located at http://www.iceis.mcnc.org/OTAGDC. The notice of proposed rulemaking for this final action, the supplemental notice of proposed rulemaking, and associated documents are located at http://epa.gov/ttn/oarpg/otagsip.html. Information related to Sections II, Weight of Evidence Determination of Covered States, and IV, Air Quality Assessment, can be obtained in electronic form from the following EPA website: http://www.epa.gov/scram001/regmodcenter/t28.htm. Information related to Section III, Determination of Budgets, may be found on the following EPA website: http://www.epa.gov/capi. All information in electronic form may also be found on diskettes that have been placed in the docket to this rulemaking.

For Additional Information

For technical questions related to the air quality analyses, please contact Norm Possiel; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD-14, Research Triangle Park, NC 27711, telephone (919) 541-5692. For legal questions, please contact Howard J. Hoffman, Office of General Counsel, 401 M Street SW, MC-2344, Washington, DC 20460, telephone (202) 260-5892. For questions concerning the statewide emissions budget revisions, please contact Laurel Schultz; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD-14, Research Triangle Park, NC 27711, telephone (919) 541-5511. For questions concerning SIP reporting requirements, please contact Bill Johnson, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC 27711, telephone (919) 541-5245. For questions concerning the model cap-and-trade rule, please contact Rob Lacount, Office of Atmospheric Programs, Acid Rain Division, MC-6204J, 401 M Street SW, Washington, DC 20460, telephone (202) 564-9122. For questions concerning the regulatory cost analysis of electricity generating sources, please contact Ravi Srivastava, Office of Atmospheric Programs, Acid Rain Division, MC-6204J, 401 M Street SW, Washington DC 20460, telephone (202) 564-9093. For questions concerning the regulatory cost analysis of other stationary sources and questions concerning the Regulatory Impact Analysis (RIA), please contact Scott Mathias, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC 27711, telephone (919) 541-5310.

Outline

CFR Revisions and Additions

I. Background

A. Summary of Rulemaking and Affected States

By notice of proposed rulemaking (NPR, proposal, or "proposed SIP call") (62 FR 60318, November 7, 1997) and by supplemental notice (SNPR or supplemental proposal) (63 FR 25902, May 11, 1998), EPA proposed to find that NO_X emissions from sources and emitting activities (sources) in 23 jurisdictions (hereinafter also referred to as States) will significantly contribute to nonattainment of the 1-hour and 8-hour ozone NAAQS, or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States throughout the Eastern United States. The EPA based these proposals on data generated by OTAG, public comments, and other relevant information. Today's final action confirms that proposed finding. It also requires, under CAA section 110(a)(1) and 110(k)(5), that the 23 jurisdictions adopt and submit SIP revisions that, in order to assure that their SIPs meet the requirements of section 110(a)(2)(D)(i)(I), contain provisions adequate to prohibit sources in those States from emitting NO_X in amounts that "contribute significantly to nonattainment in, or interfere with maintenance by," a downwind State. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Each of these States and the District of Columbia is required to adopt and submit by September 30, 1999, a SIP revision. The SIP revision must contain measures that will assure that sources in the State reduce their NO_X emissions sufficiently to eliminate the amounts of NO_X emissions that contribute significantly to nonattainment, or that interfere with maintenance, downwind. By eliminating these amounts of NO_X emissions, the control measures will assure that the remaining NO_X emissions will meet the level identified in today's rule as the State's NO_X emissions budget. For simplicity, this final rule may refer to the amounts that such SIP provisions must prohibit in order to meet the statute as the "significant amounts" of NO_X emissions. After prohibiting these significant amounts of NO_X, the remaining amounts emitted by sources in the covered States will not "significantly contribute to nonattainment, or interfere with maintenance by," a downwind State, under section 110(a)(2)(D)(i)(I). Section II.C, Weight-of-Evidence Determination of Covered States, describes how EPA determined which States include sources that emit NO_X in amounts of concern (the "covered" States), and Sections II.D, Cost Effectiveness of Emissions Reductions; II.E, Comparison of Upwind and Downwind Costs; and III, Determination of Budgets, describe how EPA determined the significant amounts of emissions and the resulting statewide emissions budgets for the States identified above. Section IV, Air Quality Assessment, discusses air quality analyses conducted by EPA which help confirm the decisions and requirements set forth in this rulemaking. Section V, NO_X Control Implementation and Budget Achievement Dates, primarily discusses the dates by which (1) the States must submit SIP revisions in response to today's action, (2) the sources must implement the measures the States choose for the purpose of prohibiting the significant amounts of NO_X, and (3) the States are projected to achieve the budget levels. Section VI, SIP Criteria and Emissions Reporting Requirements, describes the SIP requirements themselves.

The SIP requirements permit each State to determine what measures to adopt to prohibit the significant amounts and hence meet the necessary emissions budget. Consistent with OTAG's recommendations to achieve

is highly cost effective. The EPA then determined a set of controls on NO_X sources that would cost no more than an average of $2,000 per ton reduced. Specifically, EPA determined that one set of these controls would include a cap-and-trade program for (i) electricity generating boilers and turbines larger than 25 Mwe ("large EGUs"), and (ii) large non-electricity generating industrial boilers and turbines ("large non-EGU boilers and turbines"). The application of an emission rate of 0.15 lb/mmBtu and 1995–1996 utilization for EGUs and 60 percent for large non-EGUs to the emissions projected to occur in 2007 including growth and CAA measures, led to the determination of the amounts to be reduced. The remaining amount is a State's budget.

The EPA further determined that additional highly cost-effective controls are also available for cement manufacturing sources and internal combustion engines. On the basis of reasonable assumptions concerning growth to the year 2007, EPA then determined the amounts of emissions from these source categories that would be eliminated with those controls.

The EPA further determined that there were no other controls on other NO_X sources that qualify as highly cost effective (although several controls are reasonably cost-effective).

On the basis of the determinations just described for the various source categories, EPA determined an amount of NO_X emissions that may be eliminated through these highly cost-effective measures. Because EPA had also determined that the NO_X emissions from the affected upwind States have a large and/or frequent impact on downwind nonattainment or maintenance problems, EPA concludes that the amount of NO_X emissions from those States that can be eliminated through application of highly cost-effective control measures contributes significantly to nonattainment or maintenance problems downwind.

Under section 110(a)(2)(D)(i)(I), the SIP must include "adequate provisions prohibiting" sources from emitting these "amounts." Because no highly cost-effective controls are available to eliminate the remaining amounts of NO_X emissions, EPA concludes that those emissions do not contribute significantly to downwind nonattainment or maintenance problems. As indicated below and in Section III, there are cost-effective alternatives available to States that choose not to adopt all of the highly cost-effective measures on which EPA based its selection of the significant amounts of NO_X emissions.

To implement EPA's determinations, each affected upwind State is required to submit for EPA approval SIP controls projected to be sufficient, by the year 2007, to eliminate the amount of NO_X emissions in the State that EPA determined contributes significantly to nonattainment. The EPA determined this amount of reductions, for each affected upwind State, as follows: EPA first determined the amount of NO_X emissions in that State by the year 2007, based on assumptions concerning both growth and emissions controls that are required under the CAA or that will be implemented due to Federal actions (the "2007 base case"). Second, EPA applied the control measures identified as highly cost effective to the 2007 base case amount for the appropriate source categories. The amount of NO_X emissions remaining in the State after application of controls to the affected source categories constitutes the 2007 budget. The difference between the 2007 base case and the 2007 budget is the amount of NO_X emissions in that State by the year 2007 that EPA has determined to contribute significantly to nonattainment and that, therefore, the SIPs must prohibit.

The upwind State's SIP revision due in response to today's action must provide controls that, on the basis of the same assumptions (including concerning growth) made by EPA in determining the budget, would limit NO_X emissions in the year 2007 to no more than the 2007 budget. The State has full discretion in selecting the controls, so that it may choose any set of controls that would assure achievement of the budget.

As EPA stated in the NPR:

> States are not constrained to adopt measures that mirror the measures EPA used in calculating the budgets. In fact, EPA believes that many control measures not on the list relied upon to develop EPA's proposed budgets are reasonable—especially those, like enhanced vehicle inspection and maintenance programs, that yield both NO_X and VOC emissions reductions.[27] Thus, one State may choose to primarily achieve emissions reductions from stationary sources while another State may focus emission reductions from the mobile source sector. (62 FR 60328).

The EPA believes that its overall approach derives further support from the mandate in section 110(a)(2)(D) that each SIP include provisions prohibiting "any source or other type of emissions activity within the State from emitting any air pollutant in amounts' that adversely affect downwind areas. The phrase "any source or other type of emissions activity" may be interpreted to require that the SIP regulate all sources of emissions to assure that the total amount of emissions generated within the State does not adversely affect downwind areas. By its terms, the phrase covers all emitters of any kind because every emitter—stationary, mobile, or area—may be considered a "source or other type of emissions activity." This interpretation is consistent with the legislative history of the phrase. Prior to the CAA Amendments of 1990, the predecessor to section 110(a)(2)(D), which was section 110(a)(2)(E), referred to "any stationary source within the State." In the 1990 Amendments, Congress revised the phrase to read as it currently does. A Committee Report explained, "Where prohibitions in existing section 110(a)(2)(E) apply only to emissions from a single source, the amendment includes "any other type of emissions activity," which makes the provision effective in prohibiting emissions from, for example, multiple sources, mobile sources, and area sources." V Leg. Hist. 8361, S. Rep. No. 228, 101st Cong., 1st Sess. 21 (1989).

For reasons explained below, if an upwind State chooses to achieve all or a portion of the required reductions from large EGUs or large non-EGU boilers and turbines, then the SIP must include a mass emissions limitation for those sources computed with reference to certain growth assumptions and the emission rate limits chosen by the State. The EPA recommends that this mass limitation, or cap, be accompanied by a trading program. Any such cap-and-trade program must be established by May 1, 2003. If the State chooses to achieve all or a portion of the required reductions from other sources, then the State must implement controls, by the year 2003, on those other sources that are projected to achieve the required level of reductions, based on certain assumptions (including growth), in the year 2007. The controls on these other sources may be rate-based, and no emissions cap on them is required. By the year 2007, any applicable mass emissions limitation for large EGUs or large non-EGU boilers and turbines must continue to be met, and any applicable controls on other sources must continue to be implemented. The amount of the 2007 overall budget is used to compute the level of controls that would result in the appropriate amount of emissions reductions, given assumptions concerning, for example,

[27] As indicated in the NPR, EPA considers that measures may be reasonable in light of their reduction of VOC and NO_X emissions, even though their cost-effectiveness in terms of cost per NO_X emissions removed is relatively high (62 FR 60346–48).

control technology (RACT); and units with a capacity less than or equal to 250 MmBtu/hr and with emissions less than or equal to 1 ton per day were considered small sources for which no reduction would be assumed in the budget. In the SNPR, EPA specifically invited comment on the size cutoffs and on treating large industrial combustion sources (greater than 250 mmBtu or approximately 1 ton per day) at control levels equal to that for EGUs (63 FR 25909). As described below, this approach has been modified somewhat in response to comments and further analysis.

a. Proposed Control Assumptions.

Comments: Some comments supported EPA's proposed approach of assuming 70 percent and RACT controls in its calculation of the budgets. Numerous comments were received stating that the 70 percent reduction is inappropriate, may not be cost-effective and may not be achievable, especially for the following industries: cement plants; municipal waste combustors; certain pulp and paper operations, including lime kilns and recovery furnaces; glass manufacturing; steel plants; and some industrial boilers. Some comments suggested a control level of 60 percent rather than 70 percent. On the other hand, one commenter stated that SCR and SNCR are applicable and have been installed on hundreds of industrial sources.

Response: The EPA generally agrees that 70 percent emissions reduction is not appropriate for all large sources or all large source categories, even though SCR and SNCR are applicable and cost-effective for many sources. Instead of applying a one-size-fits-all percentage reduction to all large non-EGU sources, the specific emissions decreases assigned to each of these source categories for purposes of budget calculation in the final SIP Call rulemaking reflect the specific controls available for each source category that achieve the most emissions reductions at costs less than an average of $2,000 per ton. As described elsewhere in this notice, EPA's analysis results in calculating budget reductions ranging from 30 percent to 90 percent for several source categories and no controls to several other source categories.

b. Small Source Exemption.

Comments: In general, commenters were supportive of EPA including a cutoff level as part of the budget calculation; however, there were many suggestions on what the cutoff should be. The EPA received numerous comments supporting the proposed cutoff level of 25 MWe for EGUs, which is approximately equivalent to 250 mmBtu/hr or one ton per day. In addition, EPA received a few comments supporting a 250 mmBtu/hr cutoff for non-EGU point sources. Commenters indicated that the levels were appropriate and that it was important to be consistent with cutoff levels in the OTC's NO_X trading program. The Ozone Transport Commission (OTC) comprises the States of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, the northern counties of Virginia, and the District of Columbia. In September 1994, the OTC adopted a memorandum of understanding (MOU) to achieve regional emission reductions of NO_X. These reductions are in addition to previous OTC state efforts to control NO_X emissions, which included the installation of reasonably available control technology. The OTC's NO_X trading program requires utility and nonutility boilers greater than 25 MWe or 250 mmBtu to reduce emissions in order to meet a NO_X budget and allows emissions trading consistent with that budget. These NO_X reductions will take place in two phases, the first phase beginning on May 1, 1999 and the second phase on May 1, 2003.

Some comments suggested assuming budget controls on units less than or equal to 25 MWe at RACT levels without a cutoff level. Others supported EPA's proposal of assuming no additional controls on these sources. Some comments suggested exempting medium-sized non-EGU sources.

Many commenters supported the general 1 ton per day exemption contained in the NPR and SNPR. However, a few comments suggested a more stringent cutoff level of 50–100 tons per year, similar to definitions of "major source" in the CAA. One commenter recommended a less stringent level of 5 tons per day cutoff level.

A few comments suggest using tons per day as the primary criterion to define large- and medium-sized non-EGU sources, rather than boiler capacity. This approach would exempt, for example, industrial boilers that exceed the 250 mmBtu capacity, but which emit less than one ton per day on average. The EPA's proposed approach considers a source large if heat input capacity data are available and exceed the 250 mmBtu capacity criterion, regardless of its average daily emissions. In support of this approach, commenters stated that industrial operations do not usually operate at or near capacity, while EGUs often do.

A few commenters indicated that the OTAG recommendations for turbines and internal combustion engines (in terms of horsepower cutoff levels) be used. OTAG had recommended cutoff levels of 4,000 horsepower for stationary internal combustion engines and 10,000 horsepower for gas turbines.

Response: For reasons described below and in the NPR (62 FR 60354), EPA believes that the cutoff levels of 250 mmBtu/hr and 1 ton per day for large non-EGU point sources are appropriate. The EPA selected 250 mmBtu/hr and 1 ton per day primarily because this is approximately equivalent to the 25 MWe cutoff used for the EGU sector. Emission decreases from sources smaller than the heat input capacity cutoff level, and that emit less than 1 ton of NO_X per ozone season day, are not assumed as part of the budget calculation; these sources are included in the budget at baseline levels.

The EPA believes that the 1 ton per day exclusion contained in the NPR and SNPR is appropriate and necessary. This level allows today's rulemaking to focus, for the purpose of calculating the budget, on the group of emission sources that contribute the vast majority of emissions, while at the same time avoids assuming emissions reductions from a very large number of smaller sources (as described in the following paragraph). In taking today's first major step towards reducing regional transport of NO_X, EPA does not believe that emission reductions from these small sources need to be assumed. This approach provides more certainty and fewer administrative obstacles while still achieving the desired environmental results. Although other cutoff levels were suggested by commenters, EPA believes that the cutoff levels described above strike the appropriate balance so that reasonable controls may be applied by States to a sufficient but manageable number of sources to efficiently achieve the needed emission reductions.

Most small sources emit less than 100 tons of NO_X per year. Although their total emissions are low, small sources account for about 90 percent of the total number of point sources. Thus, not assuming controls on these sources at the present time would greatly limit administrative complexity and reporting costs. This common-sense approach results in reducing the non-EGU population potentially affected by the ozone transport rule from more than 13,000 sources estimated in the NPR and SNPR to under 1,200.

Although a few comments suggested using tons per day, not capacity (MWe or mmBtu/hr), for setting cutoff levels, EPA chose primarily to use capacity indicators. This approach is consistent

with EPA's proposed core group definition;

• Those who felt that the core group definition was too limiting; and

• Those who felt that the core group definition was too inclusive.

a. Commenters Who Felt the Core Group Should Not Be Changed. Commenters who supported the concept of a core group generally and the cut-offs proposed by EPA specifically explained that the cut-offs are consistent with the Acid Rain Program and that the use of a core group will minimize inconsistencies that could impede establishment of interstate trading. Commenters also added that the program should provide the flexibility to allow additional sources to opt-in on an individual basis or for States to bring in additional sources on a categorical basis. Some of these commenters added that the timing for bringing in these sources or source categories should be dependent upon the ability of the source or source category to accurately monitor emissions. For some source categories it might be appropriate to bring them in at the start of the program; for others, it might be necessary to wait until their ability to quantify emissions has improved.

Commenters who generally supported the concept of a core group of sources as it was defined in the SNPR did have several specific concerns. One commenter noted that while the SNPR preamble clearly explained that the rule only included fossil-fuel-fired units, the rule itself was not clear on this issue. Another commenter suggested that because the proposed definition differentiated between electrical generating units and non-electrical generating units it excluded sources that should be in the trading program such as cogeneration facilities that consisted of boilers greater than 250 mmBtu/hr that served electric generating units with a rating of less than 25 MWe.

The EPA agrees that the establishment of a core group will help facilitate interstate trading as well as compliance with the emissions budget. If there is not some minimum group of trading participants, sources that are in the program will have less of an opportunity to trade allowances and realize the economic benefits of trading. In addition, by ensuring that most of the emissions from industries covered by the trading program are included in a capped system, the trading program can be simplified because concerns about load shifting to uncapped sources is minimized. The EPA also agrees that making the cut-offs consistent with existing regulatory programs helps to minimize conflicts with existing regulatory programs. The EPA also agrees with both of the concerns raised by the commenters. Therefore the regulatory definition of unit has been clarified to make it clear that a unit must be fossil-fuel fired. The EPA has also added a clarification to the definition of fossil-fuel fired. This clarification is intended to define a baseline period for determining if a unit is fossil-fuel fired. The revised definition states that fossil-fuel fired means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel comprises more than 50 percent of the annual heat input on a Btu basis. An existing unit is considered fossil-fuel fired if it meets this criterion for any year since 1990 (or if not operating since 1990 during the last year of operation). A new unit is considered fossil-fuel fired if it is projected to meet this criterion or, if after operation begins, it does meet this criterion.

In addition, to address the concern about excluding cogeneration facilities that are greater than 250 mmBtu/hr that serve electric generating units with a rating of less than 25 MWe, the applicability has been changed to include all units greater than 250 mmBtu/hr, regardless of how much electricity they generate.

b. Commenters Who Felt the Core Group Should Be Expanded. Commenters who felt the trading program should be expanded focused on a number of areas. Several commenters argued generally that the program should allow any source to participate if the source can document that emissions reductions have been achieved. A number of commenters mentioned as examples the inclusion of medium-sized and smaller stationary sources in the RECLAIM program. A few commenters argued that the addition of certain sources is needed for consistency with the OTC NO_X Budget Rule. Other commenters opposed the core group concept because they believe that regulation of low-level and local sources in the Northeast is an essential step in solving the ozone problem. Others argued that excluding non-utility sources from the trading program unfairly excludes these sources from least-cost compliance options. Some commenters suggested specific categories of units that should be allowed to, but not required to, participate in the trading program. These included:

(1) Municipal waste combustors;

(2) Internal combustion engines;

(3) Process units;

(4) Units for which the output product is not comparable to other units on which the allocations are based, such as process heaters, hazardous waste incinerators, process vents and nitric acid plants.

The EPA believes that many of the concerns about the core source definition stem from a misunderstanding of its purpose. The core sources definition was intended to indicate the minimum applicability requirements that a State rule would have to include to participate in a larger multi-state program that EPA would help to administer. It was not intended to limit individual States from including more sources (as long as the sources meet certain criteria further explained below) in the larger multi-state program (63 FR 25924). Nor was it intended to prohibit a State (or group of States) from developing its own trading program with a more limited applicability.

If, however, a State or group of States developed a trading program that did not meet the minimum requirements set forth in the model $NO^{\times}$ Budget Trading Program, such as minimum core source applicability, EPA would not participate in the administration of such a trading program. This is because it would not be administratively cost-efficient for EPA to manage multiple trading programs with a variety of applicability and other requirements designed to address the same issue.

The EPA is not expanding the core source group to include any additional sources because EPA believes that this decision is better left to the states. Therefore the model rule will allow a State to expand the applicability of the trading program to include additional stationary sources if the sources meet certain criteria. These criteria include the ability to accurately and consistently monitor and report emissions and the ability to identify a party responsible for ensuring that monitoring and reporting requirements are met, for authorizing allowance transfers and for ensuring compliance. The EPA's rationale for setting these minimum criteria are set forth in the preamble to the SNPR (63 FR 25923). Also, EPA addresses issues specifically related to the monitoring requirements for these sources in Section D.3 of today's preamble.

There are two mechanisms that can be used to include more sources in the program. One is for a State to expand the applicability criteria to include other source categories; the other is to give individual sources the ability to opt-in.

States that choose to expand the applicability criteria can do so (1) by lowering the applicability threshold for source categories that are already part of

alternative compliance options for units with low NO_X mass emissions, explained below. Combustion turbines smaller than 100 MWe are also likely candidates to qualify for the alternative compliance option explained below.

The Acid Rain Program exempts cyclone boilers with a maximum continuous steam flow at 100 percent load of greater than 1060 thousand lb/hr from NO_X control requirements under part 76. These units were exempted because one of the primary criteria in title IV of the CAA for setting emissions limitations under part 76 was comparability of cost with low NO_X emission controls on boilers categorized as group 1 boilers under Title IV (large tangentially fired and dry bottom, wall fired). There is no such criterion in the CAA applicable to this rulemaking. Also, since the emission reductions required by this rulemaking are more substantial than the emission reductions required under part 76 [70], the cost per ton of reducing NO_X emission reductions is correspondingly higher. Therefore, applicability cutoffs that were relevant in the part 76 rulemaking are not relevant in this rulemaking.

In response to the comment that small electrical generators less than 25 MWe should be exempt from the NO_X Budget Trading Program, they were proposed to be exempt and will be exempt under the final model rule. They do still have the option of opting into the program if they choose to do so.

In the SNPR (63 FR 25926), EPA took comment on allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per ozone season), that because of their size would be included in the trading program, to be exempt from the requirements of the trading program. In general commenters supported this concept. One commenter who supported the concept also added that it would be important to ensure that there were adequate requirements to assure that the individual sources who took advantage of this option demonstrated compliance with their unit-specific caps. The commenters who disagreed with this option expressed concern that a State's budget could be exceeded if emissions from these units were not accounted for.

Based on the comments received EPA continues to believe that it is appropriate to offer States the option of providing units that are above the applicability threshold but that have a very low potential to emit an alternative compliance option. This option would allow units that meet the requirements described below to be exempt from the requirements to hold allowances, and to comply with quarterly reporting requirements. In order to address the concern that sources must demonstrate compliance with their individual cap, EPA has added specific requirements that sources must meet in order to use this alternative compliance option.

Units that use this option would be required to:

(1) have a federally enforceable permit restricting ozone season emissions to less than 25 tons;

(2) keep on site records demonstrating that the conditions of the permit were met, including restrictions on operating time;

(3) report hours of operation during the ozone season to the permitting authority on an annual basis.

A unit choosing to use this compliance option would be required to determine the appropriate restrictions on its operating time by dividing 25 tons by the unit's maximum potential hourly NO_X mass emissions. The unit's maximum potential hourly NO_X mass emissions would be determined by multiplying the highest default emission rate for any fuel that the unit burned (using the default emission rates, in part 75.19 of this chapter) by the maximum rated hourly heat input of the unit (as defined in part 72 of this chapter).

States would be allowed, but not required, to incorporate this alternative compliance option into their SIPs. The EPA does agree that if a State does incorporate this option into the SIP, it would have to account for the emissions under its budget. Thus a State that chose to use this option would have to either:

(1) Subtract the total amount of potential emissions permitted to be emitted using this approach from the trading portion of the budget before the remaining portion of the trading budget is allocated to the trading participants; or (2) Offset the difference between total amount of potential emissions permitted to be emitted using this approach and the 2007 base year inventory emissions for these same sources with additional reductions outside of the trading portion of the budget.

If States choose not to incorporate this alternative compliance option into their SIPs, or if they choose to incorporate it exactly as it is set forth in the model rule, it will not affect the streamlined approval of the trading rule portion of the SIP. A State may choose to require an alternative means of ensuring that the potential to emit for units utilizing the alternative means of compliance is limited to less than 25 tons, however if a State deviates from the model rule in this way, the SIP will no longer receive streamlined approval.

2. Mobile/Area Sources

The proposed rule did not include mobile or area sources in the trading program, but solicited comment on expanding applicability to include these sources, or to include credits generated by these sources, in the trading program. Mobile and area sources were not included in the proposed trading rule due to EPA's concerns related to ensuring that reductions were real, developing and implementing procedures for monitoring emissions, and identifying responsible parties for the implementation of the program and associated emissions reductions.

The EPA received comment from State and local government, industry and coalitions of industry, and environmental groups regarding the inclusion of mobile and area sources in the program. Comments focused on the following main areas: inclusion or exclusion of mobile and area sources, subcategories of mobile sources for inclusion, and the use of pilot programs to foster innovation.

Some commenters urged EPA to include mobile and area sources with as few restrictions as possible in the trading program, primarily on an opt-in or voluntary basis. These commenters argued that excluding mobile sources would reduce the potential scope and benefits of the trading by placing a large portion of States' NO_X inventory outside the scope of the trading program. They noted that the existence of RECLAIM protocols for mobile and area source credit generation demonstrated that EPA's quantification, verification, and administration concerns were misplaced.

The majority of commenters, however, indicated that mobile sources should not be included at this time and that the model rule should not be delayed to address concerns related to inclusion of these sources. Some commenters argued against ever including mobile and area sources in the program. One State argued that inclusion of mobile and area sources would destroy the integrity of the program since mobile and area source reductions are not necessarily real, verifiable and quantifiable, failing to display a level of certainty comparable to those sources included in the trading program. A few commenters indicated that mobile sources were inherently unsuited to a capped system, since the difficulties of measuring emissions from these sources precludes their inclusion in a budget.

[70] The lowest emission rate required under part 76 is 0.40 lbs/mmBtu.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in appendix A of part 60 of this chapter.

Serial number means, when referring to NO_X allowances, the unique identification number assigned to each NO_X allowance by the Administrator, under § 96.53(c).

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the CAA. For purposes of section 502(c) of the CAA, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the 48 contiguous States and the District of Columbia specified in § 51.121 of this chapter, or any non-federal authority in or including such States or the District of Columbia (including local agencies, and Statewide agencies) or any eligible Indian tribe in an area of such State or the District of Columbia, that adopts a NO_X Budget Trading Program pursuant to § 51.121 of this chapter. To the extent a State incorporates by reference the provisions of this part, the term "State" shall mean the incorporating State. The term "State" shall have its conventional meaning where such meaning is clear from the context.

State trading program budget means the total number of NO_X tons apportioned to all NO_X Budget units in a given State, in accordance with the NO_X Budget Trading Program, for use in a given control period.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Ton or tonnage means any "short ton" (i.e., 2,000 pounds). For the purpose of determining compliance with the NO_X Budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with subpart H of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons.

Unit means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit load means the total (i.e., gross) output of a unit in any control period (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

(1) The total electrical generation (MWe) produced by the unit, including generation for use within the plant; or

(2) In the case of a unit that uses heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit, including steam for use by the unit.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means any hour (or fraction of an hour) during which a unit combusts any fuel.

Utilization means the heat input (expressed in mmBtu/time) for a unit. The unit's total heat input for the control period in each year will be determined in accordance with part 75 of this chapter if the NO_X Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

§ 96.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
hr—hour.
Kwh—kilowatt hour.
lb—pounds.
mmBtu—million Btu.
MWe—megawatt electrical.
ton—2000 pounds.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
O_2—oxygen.

§ 96.4 Applicability.

(a) The following units in a State shall be NO_X Budget units, and any source that includes one or more such units shall be a NO_X Budget source, subject to the requirements of this part:

(1) Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than 25 MWe and sells any amount of electricity; or

(2) Any unit that is not a unit under paragraph (a) of this section and that has a maximum design heat input greater than 250 mmBtu/hr.

(b) Notwithstanding paragraph (a) of this section, a unit under paragraph (a) of this section shall be subject only to the requirements of this paragraph (b) if the unit has a federally enforceable permit that meets the requirements of paragraph (b)(1) of this section and restricts the unit to burning only natural gas or fuel oil during a control period in 2003 or later and each control period thereafter and restricts the unit's operating hours during each such control period to the number of hours (determined in accordance with paragraph (b)(1)(ii) and (iii) of this section) that limits the unit's potential NO_X mass emissions for the control period to 25 tons or less. Notwithstanding paragraph (a) of this section, starting with the effective date of such federally enforceable permit, the unit shall not be a NO_X Budget unit.

(1) For each control period under paragraph (b) of this section, the federally enforceable permit must:

(i) Restrict the unit to burning only natural gas or fuel oil.

(ii) Restrict the unit's operating hours to the number calculated by dividing 25 tons of potential NO_X mass emissions by the unit's maximum potential hourly NO_X mass emissions.

(iii) Require that the unit's potential NO_X mass emissions shall be calculated as follows:

(A) Select the default NO_X emission rate in Table 2 of § 75.19 of this chapter that would otherwise be applicable assuming that the unit burns only the type of fuel (i.e., only natural gas or only fuel oil) that has the highest default NO_X emission factor of any type of fuel that the unit is allowed to burn under the fuel use restriction in paragraph (b)(1)(i) of this section; and

(B) Multiply the default NO_X emission rate under paragraph (b)(1)(iii)(A) of this section by the unit's maximum rated hourly heat input. The owner or operator of the unit may petition the permitting authority to use a lower value for the unit's maximum rated hourly heat input than the value as defined under § 96.2. The permitting authority may approve such lower value if the owner or operator demonstrates that the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and that such lower value is representative, of the unit's current capabilities because

modifications have been made to the unit, limiting its capacity permanently.

(iv) Require that the owner or operator of the unit shall retain at the source that includes the unit, for 5 years, records demonstrating that the operating hours restriction, the fuel use restriction, and the other requirements of the permit related to these restrictions were met.

(v) Require that the owner or operator of the unit shall report the unit's hours of operation (treating any partial hour of operation as a whole hour of operation) during each control period to the permitting authority by November 1 of each year for which the unit is subject to the federally enforceable permit.

(2) The permitting authority that issues the federally enforceable permit with the fuel use restriction under paragraph (b)(1)(i) and the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section will notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority includes such restrictions. The permitting authority will also notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority is revised to remove any such restriction, whose federally enforceable permit issued by the permitting authority includes any such restriction that is no longer applicable, or which does not comply with any such restriction.

(3) If, for any control period under paragraph (b) of this section, the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section is removed from the unit's federally enforceable permit or otherwise becomes no longer applicable or if, for any such control period, the unit does not comply with the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section, the unit shall be a NO_X Budget unit, subject to the requirements of this part. Such unit shall be treated as commencing operation and, for a unit under paragraph (a)(1) of this section, commencing commercial operation on September 30 of the control period for which the fuel use restriction or the operating hours restriction is no longer applicable or during which the unit does not comply with the fuel use restriction or the operating hours restriction.

§ 96.5 Retired unit exemption.

(a) This section applies to any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired.

(b)(1) Any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired shall be exempt from the NO_X Budget Trading Program, except for the provisions of this section, §§ 96.2, 96.3, 96.4, 96.7 and subparts E, F, and G of this part.

(2) The exemption under paragraph (b)(1) of this section shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NO_X authorized account representative (authorized in accordance with subpart B of this part) shall submit a statement to the permitting authority otherwise responsible for administering any NO_X Budget permit for the unit. A copy of the statement shall be submitted to the Administrator. The statement shall state (in a format prescribed by the permitting authority) that the unit is permanently retired and will comply with the requirements of paragraph (c) of this section.

(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority will amend any permit covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (b)(1) and (c) of this section.

(c) *Special provisions.* (1) A unit exempt under this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with subpart E of this part.

(2)(i) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(ii) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a non-title V permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(3) The owners and operators and, to the extent applicable, the NO_X authorized account representative of a unit exempt under this section shall comply with the requirements of the NO_X Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit that is exempt under this section is not eligible to be a NO_X Budget opt-in source under subpart I of this part.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) *Loss of exemption.* (i) On the earlier of the following dates, a unit exempt under paragraph (b) of this section shall lose its exemption:

(A) The date on which the NO_X authorized account representative submits a NO_X Budget permit application under paragraph (c)(2) of this section; or

(B) The date on which the NO_X authorized account representative is required under paragraph (c)(2) of this section to submit a NO_X Budget permit application.

(ii) For the purpose of applying monitoring requirements under subpart H of this part, a unit that loses its exemption under this section shall be treated as a unit that commences operation or commercial operation on the first date on which the unit resumes operation.

§ 96.6 Standard requirements.

(a) *Permit Requirements.* (1) The NO_X authorized account representative of each NO_X Budget source required to have a federally enforceable permit and each NO_X Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NO_X Budget permit application under § 96.22 in accordance

binding on the new alternate NO_X authorized account representative and the owners and operators of the NO_X Budget source and the NO_X Budget units at the source.

(c) *Changes in the owners and operators.* (1) In the event a new owner or operator of a NO_X Budget source or a NO_X Budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the NO_X authorized account representative and any alternate NO_X authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the permitting authority or the Administrator, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a NO_X Budget source or a NO_X Budget unit, including the addition of a new owner or operator, the NO_X authorized account representative or alternate NO_X authorized account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

§ 96.13 Account certificate of representation.

(a) A complete account certificate of representation for a NO_X authorized account representative or an alternate NO_X authorized account representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the NO_X Budget source and each NO_X Budget unit at the source for which the account certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO_X authorized account representative and any alternate NO_X authorized account representative.

(3) A list of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source.

(4) The following certification statement by the NO_X authorized account representative and any alternate NO_X authorized account representative: "I certify that I was selected as the NO_X authorized account representative or alternate NO_X authorized account representative, as applicable, by an agreement binding on the owners and operators of the NO_X Budget source and each NO_X Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO_X Budget Trading Program on behalf of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the permitting authority, the Administrator, or a court regarding the source or unit."

(5) The signature of the NO_X authorized account representative and any alternate NO_X authorized account representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.14 Objections concerning the NO_X authorized account representative.

(a) Once a complete account certificate of representation under § 96.13 has been submitted and received, the permitting authority and the Administrator will rely on the account certificate of representation unless and until a superseding complete account certificate of representation under § 96.13 is received by the Administrator.

(b) Except as provided in § 96.12(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO_X authorized account representative shall affect any representation, action, inaction, or submission of the NO_X authorized account representative or the finality of any decision or order by the permitting authority or the Administrator under the NO_X Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO_X authorized account representative, including private legal disputes concerning the proceeds of NO_X allowance transfers.

Subpart C—Permits

§ 96.20 General NO_X Budget trading program permit requirements.

(a) For each NO_X Budget source required to have a federally enforceable permit, such permit shall include a NO_X Budget permit administered by the permitting authority.

(1) For NO_X Budget sources required to have a title V operating permit, the NO_X Budget portion of the title V permit shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such title V operating permits regulations shall include, but are not limited to, those provisions addressing operating permit applications, operating permit application shield, operating permit duration, operating permit shield, operating permit issuance, operating permit revision and reopening, public participation, State review, and review by the Administrator.

(2) For NO_X Budget sources required to have a non-title V permit, the NO_X Budget portion of the non-title V permit shall be administered in accordance with the permitting authority's regulations promulgated to administer non-title V permits, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such non-title V permits regulations may include, but are not limited to, provisions addressing permit applications, permit application shield, permit duration, permit shield, permit issuance, permit revision and reopening, public participation, State review, and review by the Administrator.

(b) Each NO_X Budget permit (including a draft or proposed NO_X Budget permit, if applicable) shall contain all applicable NO_X Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.

§ 96.21 Submission of NO_X Budget permit applications.

(a) *Duty to apply.* The NO_X authorized account representative of any NO_X Budget source required to have a federally enforceable permit shall submit to the permitting authority a complete NO_X Budget permit application under § 96.22 by the applicable deadline in paragraph (b) of this section.

(b)(1) For NO_X Budget sources required to have a title V operating permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(2) For NO_X Budget sources required to have a non-title V permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(c) *Duty to reapply.* (1) For a NO_X Budget source required to have a title V operating permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's title V operating permits regulations addressing operating permit renewal.

(2) For a NO_X Budget source required to have a non-title V permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's non-title V permits regulations addressing permit renewal.

§ 96.22 Information requirements for NO_X Budget permit applications.

A complete NO_X Budget permit application shall include the following elements concerning the NO_X Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the NO_X Budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration, if applicable;

(b) Identification of each NO_X Budget unit at the NO_X Budget source and whether it is a NO_X Budget unit under § 96.4 or under subpart I of this part;

(c) The standard requirements under § 96.6; and

(d) For each NO_X Budget opt-in unit at the NO_X Budget source, the following certification statements by the NO_X authorized account representative:

(1) "I certify that each unit for which this permit application is submitted under subpart I of this part is not a NO_X Budget unit under 40 CFR 96.4 and is not covered by a retired unit exemption under 40 CFR 96.5 that is in effect."

(2) If the application is for an initial NO_X Budget opt-in permit, "I certify that each unit for which this permit application is submitted under subpart I is currently operating, as that term is defined under 40 CFR 96.2."

§ 96.23 NO_X Budget permit contents.

(a) Each NO_X Budget permit (including any draft or proposed NO_X Budget permit, if applicable) will contain, in a format prescribed by the permitting authority, all elements required for a complete NO_X Budget permit application under § 96.22 as approved or adjusted by the permitting authority.

(b) Each NO_X Budget permit is deemed to incorporate automatically the definitions of terms under § 96.2 and, upon recordation by the Administrator under subparts F, G, or I of this part, every allocation, transfer, or deduction of a NO_X allowance to or from the compliance accounts of the NO_X Budget units covered by the permit or the overdraft account of the NO_X Budget source covered by the permit.

§ 96.24 Effective date of initial NO_X Budget permit.

The initial NO_X Budget permit covering a NO_X Budget unit for which a complete NO_X Budget permit application is timely submitted under § 96.21(b) shall become effective by the later of:

(a) May 1, 2003;

(b) May 1 of the year in which the NO_X Budget unit commences operation, if the unit commences operation on or before May 1 of that year;

(c) The date on which the NO_X Budget unit commences operation, if the unit commences operation during a control period; or

(d) May 1 of the year following the year in which the NO_X Budget unit commences operation, if the unit commences operation on or after October 1 of the year.

§ 96.25 NO_X Budget permit revisions.

(a) For a NO_X Budget source with a title V operating permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

(b) For a NO_X Budget source with a non-title V permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's non-title V permits regulations addressing permit revisions.

Subpart D—Compliance Certification

§ 96.30 Compliance certification report.

(a) *Applicability and deadline.* For each control period in which one or more NO_X Budget units at a source are subject to the NO_X Budget emissions limitation, the NO_X authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) *Contents of report.* The NO_X authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NO_X Budget emissions limitation for the control period covered by the report:

(1) Identification of each NO_X Budget unit;

monitoring NO_X mass. This includes all systems required to monitor NO_X emission rate, NO_X concentration, heat input, and flow, in accordance with §§ 75.72 and 75.76.

(2) Install all monitoring systems for monitoring heat input, if required under § 96.76 for developing NO_X allowance allocations.

(3) Successfully complete all certification tests required under § 96.71 and meet all other provisions of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.

(4) Record, and report data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

(b) *Compliance dates.* The owner or operator must meet the requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates and must record and report data on and after the following dates:

(1) NO_X Budget units for which the owner or operator intends to apply for early reduction credits under § 96.55(d) must comply with the requirements of this subpart by May 1, 2000.

(2) Except for NO_X Budget units under paragraph (b)(1) of this section, NO_X Budget units under § 96.4 that commence operation before January 1, 2002, must comply with the requirements of this subpart by May 1, 2002.

(3) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on an annual basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) May 1, 2002; or

(ii) The earlier of:

(A) 180 days after the date on which the unit commences operation or, (B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(4) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on a control season basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) The earlier of:

(A) 180 days after the date on which the unit commences operation or,

(B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(ii) However, if the applicable deadline under paragraph (b)(4)(i) section does not occur during a control period, May 1; immediately following the date determined in accordance with paragraph (b)(4)(i) of this section.

(5) For a NO_X Budget unit with a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2) or (b)(3) of this section or subpart I of this part:

(i) 90 days after the date on which emissions first exit to the atmosphere through the new stack or flue;

(ii) However, if the unit reports on a control season basis under § 96.74(d) and the applicable deadline under paragraph (b)(5)(i) of this section does not occur during the control period, May 1 immediately following the applicable deadline in paragraph (b)(5)(i) of this section.

(6) For a unit for which an application for a NO_X Budget opt in permit is submitted and not denied or withdrawn, the compliance dates specified under subpart I of this part.

(c) *Reporting data prior to initial certification.* (1) The owner or operator of a NO_X Budget unit that misses the certification deadline under paragraph (b)(1) of this section is not eligible to apply for early reduction credits. The owner or operator of the unit becomes subject to the certification deadline under paragraph (b)(2) of this section.

(2) The owner or operator of a NO_X Budget under paragraphs (b)(3) or (b)(4) of this section must determine, record and report NO_X mass, heat input (if required for purposes of allocations) and any other values required to determine NO_X Mass (e.g. NO_X emission rate and heat input or NO_X concentration and stack flow) using the provisions of § 75.70(g) of this chapter, from the date and hour that the unit starts operating until all required certification tests are successfully completed.

(d) *Prohibitions.* (1) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with § 96.75.

(2) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(3) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(4) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under § 96.5 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The NO_X authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 96.71(b)(2).

§ 96.71 Initial certification and recertification procedures

(a) The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter, except that:

(1) If, prior to January 1, 1998, the Administrator approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.17 of this chapter, the NO_X authorized account representative shall resubmit the petition to the Administrator under § 96.75(a) to determine if the approval applies under the NO_X Budget Trading Program.

(2) For any additional CEMS required under the common stack provisions in § 75.72 of this chapter, or for any NO_X concentration CEMS used under the provisions of § 75.71(a)(2) of this chapter, the owner or operator shall

meet the requirements of paragraph (b) of this section.

(b) The owner or operator of a NO_X Budget unit that is not subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures, except that the owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 shall also meet the requirements of paragraph (c) of this section and the owner or operator of a unit that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall also meet the requirements of paragraph (d) of this section. The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation, but requires additional CEMS under the common stack provisions in § 75.72 of this chapter, or that uses a NO_X concentration CEMS under § 75.71(a)(2) of this chapter also shall comply with the following initial certification and recertification procedures.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each monitoring system required by subpart H of part 75 of this chapter (which includes the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter. The owner or operator shall ensure that all applicable certification tests are successfully completed by the deadlines specified in § 96.70(b). In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this part in a location where no such monitoring system was previously installed, initial certification according to § 75.20 is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in a certified monitoring system that the Administrator or the permitting authority determines significantly affects the ability of the system to accurately measure or record NO_X mass emissions or heat input or to meet the requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system according to § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the permitting authority determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to § 75.20(b) of this chapter. Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) *Certification approval process for initial certifications and recertification.* (i) *Notification of certification.* The NO_X authorized account representative shall submit to the permitting authority, the appropriate EPA Regional Office and the permitting authority a written notice of the dates of certification in accordance with § 96.73.

(ii) *Certification application.* The NO_X authorized account representative shall submit to the permitting authority a certification application for each monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter.

(iii) Except for units using the low mass emission excepted methodology under § 75.19 of this chapter, the provisional certification date for a monitor shall be determined using the procedures set forth in § 75.20(a)(3) of this chapter. A provisionally certified monitor may be used under the NO_X Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system or component thereof under paragraph (b)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the permitting authority.

(iv) *Certification application formal approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (b)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the NO_X Budget Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* A certification application will be considered complete when all of the applicable information required to be submitted under paragraph (b)(3)(ii) of this section has been received by the permitting authority. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the NO_X authorized account representative must submit the additional information required to complete the certification application. If the NO_X authorized account representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (b)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of this part, or if the certification application is incomplete and the requirement for disapproval under paragraph (b)(3)(iv)(B) of this section has been met, the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality-assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in paragraph (b)(3)(v) of this section for each monitoring system or component thereof which is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.72(b).

(v) *Procedures for loss of certification.* If the permitting authority issues a notice of disapproval of a certification application under paragraph

(b)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (b)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under § 75.20(a)(5)(i) of this chapter:

(1) For units using or intending to monitor for NO_X emission rate and heat input or for units using the low mass emission excepted methodology under § 75.19 of this chapter, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit.

(2) For units intending to monitor for NO_X mass emissions using a NO_X pollutant concentration monitor and a flow monitor, the maximum potential concentration of NO_X and the maximum potential flow rate of the unit under section 2.1 of appendix A of part 75 of this chapter;

(B) The NO_X authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (b)(3)(i) and (ii) of this section; and

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 of this chapter shall meet the applicable general operating requirements of § 75.10 of this chapter, the applicable requirements of § 75.19 of this chapter, and the applicable certification requirements of § 96.71 of this chapter, except that the excepted methodology shall be deemed provisionally certified for use under the NO_X Budget Trading Program, as of the following dates:

(1) For units that are reporting on an annual basis under § 96.74(d):

(i) For a unit that has commences operation before its compliance deadline under § 96.71(b), from January 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commences operation after its compliance deadline under § 96.71(b), the date of submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for permitting authority review, or

(2) For units that are reporting on a control period basis under § 96.74(b)(3)(ii) of this part:

(i) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted before May 1, from May 1 of the year of the submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, from May 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(iii) For a unit that commences operation after its compliance deadline under § 96.71(b), where the unit commences operation before May 1, from May 1 of the year that the unit commenced operation, until the completion of the period for the permitting authority's review.

(iv) For a unit that has not operated after its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, but before October 1st, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority's review.

(d) Certification/recertification procedures for alternative monitoring systems. The NO_X authorized account representative representing the owner or operator of each unit applying to monitor using an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall apply for certification to the permitting authority prior to use of the system under the NO_X Trading Program. The NO_X authorized account representative shall apply for recertification following a replacement, modification or change according to the procedures in paragraph (b) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification according to the procedures specified in paragraph (b)(3) of this section and § 75.20(f) of this chapter.

§ 96.72 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality assurance requirements of appendix B of part 75 of this chapter, data shall be substituted using the applicable procedures in subpart D, appendix D, or appendix E of part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.71 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the system or component. The data measured and recorded by the system or component shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the initial certification or recertification procedures in § 96.71 for each disapproved system.

§ 96.73 Notifications.

The NO_X authorized account representative for a NO_X Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

Responses to Significant Comments on the Proposed Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport

(63 FR 24058, April 30, 1998; 63 FR 52213, September 30, 1998; 63 FR 56292, October 21, 1998; 64 FR 2416, January 13, 1999; 64 FR 10118, March 2, 1999; and 64 FR 10342, March 3, 1999)

Docket Number A-97-43, VI-C-01

U.S. Environmental Protection Agency
April 1999

Exhibit B

pool also provides further allowances in the trading market for the first two years of the program (see compliance supplement pool discussion in Section IV of final rule preamble). In addition, many States are in the process of developing a trading program under the NOx SIP call. Since, a trading program will be promulgated by EPA for this section 126 rulemaking all sources subject to any final section 126 remedy will be subject to the trading program.

SUMMARY: Commenter objects to EPA's denial of commenter's petition with respect to large process heaters. Commenter points that implementation of a regional NOx budget program adopted by the OTC indicates that a trading program is available for these sources within the OTC. Commenter questions why such a similar program is not being imposed by EPA on large process heaters.

LETTERS: Connecticut Dept. of Environmental Protection (IV-D-19), Midwest Ozone Group (V-H-58), Pennsylvania Power & Light, Inc. (V-H-119)

RESPONSE: Table 7-10 of the Regulatory Impacts Analysis (RIA) for the NOx SIP call (Volume 1, September 1998) shows the annual costs and resulting average cost-effectiveness for each regulatory alternative for process heaters. Annual monitoring and administrative costs are not estimated for this category of sources because it is evident from Table 7-10 that even without these additional costs there is no regulatory alternative that meets EPA's criteria for highly cost-effective ozone season NOx emissions reductions. That is, when emissions decreases are considered at all large process heating sources (i.e., regulatory alternatives applying greater than $4,000/ton of control), the resulting average cost-effectiveness clearly exceeds EPA's cost-effectiveness criteria of less than $2,000 per ton of $_{NOx}$ reduction.

Although a trading program is available for process heaters under the OTC, EPA has determined that controlling process heaters across the entire region potentially covered by section 126 is not highly cost effective. If EPA were to include monitoring costs in its cost-effectiveness number and assume that a trading program would achieve a 30 percent reduction in the cost-effectiveness number, controlling process heaters would still cost more than $2,000 per ton of NOx removed. Thus, for the final rule, EPA concludes that process heaters do not emit in amounts that significantly contribute to petitioning States' nonattainment or maintenance problems.

SUMMARY: Commenters object to EPA's denial of commenter's petition with respect to EGUs between 15 and 25 MW. Commenters advocates capping such sources at 1990 levels consistent with the OTC NOx MOU. The commenters argued that this action would be highly cost-effective since it would not require additional controls in a market driven NOx control program. One commenter argued that inclusion of these sources will control the shifting of power production to smaller sources. One of the commenters stated that control

of 15-25 MWe boilers is highly cost effective because they believe that the petitions clearly demonstrate these sources do have a significant impact.

LETTERS: Connecticut Dept. of Environmental Protection (IV-D-19), New York Dept. of Environmental Conservation (II-D-5), Pennsylvania Dept. of Environmental Protection (II-D-26), Midwest Ozone Group (V-H-58), Pennsylvania Power & Light, Inc. (V-H-119), (Maine, IV-D-75)

RESPONSE: In the NOx SIP call (see 63 FR at 57402), EPA found that the collective emissions from small sources were relatively small (in the context of that rulemaking) and the administrative burden, to the permitting authority and to regulated entities, of controlling such sources was likely to be considerable. Even if EPA were not to apply additional controls beyond capping small sources at 1990 levels, there would be administrative costs that would be considerable in comparison to the emissions reductions gained. Thus, controlling small sources (less than 25 MWe) is not appropriate for EPA to mandate.

Data is often lacking for the smaller size sources. This level allows the rulemaking to focus on the group of emission sources that contribute the vast majority of emissions, while at the same time avoids assuming emissions reductions from a very large number of smaller sources. This approach provides more certainty and fewer administrative obstacles while still achieving the desired environmental results.

Assuming controls on the smaller EGUs would also be inconsistent with the approach EPA proposed and is taking for non-EGUs. That is, the 250 mmBtu non-EGU cutoff is approximately equivalent to the 25 MWe cutoff level for EGUs. EPA is generally treating the non-EGU boilers/turbines in the same manner as the EGUs to develop a simple and effective trading program. Consistency with the EGU approach is also important because it provides equity, especially among the smaller boilers and turbines.

Finally, EPA maintains that the potential for shifting power production to smaller unaffected sources is minimized because such a large portion of electric generating units are subject to the NOx trading program. In the final action, EPA concludes that small sources do not emit in amounts that significantly contribute to petitioning States' nonattainment or maintenance problems.

SECTION IV.D. Compliance Supplement Pool

SUMMARY: Most commenters expressed support for a compliance supplement pool as part of the trading program. However, others noted that the compliance supplement pool may not be appropriate and/or legal as part of a section 126 remedy because it could result in an extended compliance period beyond the 3-year requirement provided for under section 126. Another commenter stated specifically that the compliance supplement pool should not be included along with the FIP. Other commenters noted that requiring the use of compliance supplement pool credits by 2004 provided no environmental benefit. Finally, two

EPA has taken a fuel neutral approach in establishing 0.15 lb/mmBtu limit which does not favor one fuel type over another. A 0.05 lb/mmBtu control level for gas and oil-fired units selected would effect the cost-effectiveness (possibly increasing costs) because it would limit the number of allowances available for trading. EPA believes that 0.15 lb/mmbtu limit can easily be achieved by gas and oil-fired boilers, of which over half already operate at NOx levels below a 0.15 lb/MMBtu emission limit and should therefore easily be able to generate emission credits if trading is allowed. The EPA recognizes that for coal-fired boilers to operate at or below this limit, Selective Catalytic Reduction (SCR) will generally be necessary. However, under a trading scenario, if one coal-fired boiler is able to emit below this level by installing SCR, it can provide emission credits to another boiler, thus obviating the need for that boiler to install SCR. The EPA believes that ample allowances would exist to sustain a market under the NOx Budget Trading Program. Results of an analysis of this issue can be found in the RIA.

Therefore, EPA believes that the 0.15 lb/MMBtu standard is reasonable and appropriate.

SUMMARY: Commenter supports considering the average cost of control and not differentiating between large and small sources within the affected category because with the anticipated trading program, units with high costs of control will be able to trade with those having lower control costs to minimize the overall cost of control.

LETTERS: NY DEC (II-D5)

RESPONSE: EPA believes that trading for large combustion sources under a budget that is developed based on this limit is a feasible, cost-effective means of meeting the budget. The EPA performed an analysis to determine the cost effectiveness of NOx controls applied to large utility boilers and how it compared to other section NOx controls. The results indicate that controlling emissions to an average level of 0.15 lb/MMBtu was highly cost effective. EPA found that the collective emissions from small sources were relatively small and the administrative burden, to the permitting authority and to regulated entities, of controlling such sources was likely to be considerable in comparison to the emissions reductions gained. Thus, controlling small sources (less than 25 MWe) is not appropriate for EPA to mandate.

SUMMARY: A number of commenters supported a phased-in approach. These alternatives included the phase-in proposals submitted by ACAP and the Midwest/Southeast Governors Ozone Coalition, as well as other various proposals. Other commenters, however, opposed any phase-in approach because delaying or phasing in the NOx reductions will negatively impact the environment.

LETTERS: Allegheny Power (V-H-140), Indiana Department of Environmental Management (V-H-116), New Hampshire Department of Environmental Services (V-I-39), West Virginia Chamber of Commerce (V-H-173), Cinergy (II-D-23)

times for completing SCR installation and found that power did move between regions in the event of longer outage times.

- **UARG maintains that scheduling outages may be a problem given the advent of competition.** According to UARG, utilities may be unwilling to coordinate their outage schedules in light of increased competition in the electric power industry. EPA maintains that it is reasonable to assume that utilities will continue to cooperate and coordinate their outage schedules as they currently do. Even with increased competition, utilities and independent power producers will likely be concerned about reliability and the need for coordination, particularly since customers will have an increased ability to change electric suppliers.

- **UARG states that there may not be enough catalyst for the amount of SCR installation that they believe will occur.** UARG did not provide any support for the assumption that the supply of catalyst will be insufficient. EPA's *Feasibility of Installing $_{NOx}$ Control Technologies by May 2003* demonstrates that it would not be a problem to provide the amount of catalyst that UARG maintains is needed.

EPA also notes that the ECAR letter to Carol Browner points out reliability concerns raised in the ten-year assessment of ECAR-wide capacity margins that it appears could be exacerbated by the $_{NOx}$ SIP Call. However, the ECAR ten-year assessment actually raised concerns for reliability during the summer peak period, whereas the installation of SCR technology will occur during off-peak periods. (See Memo from ICF Kaiser to EPA dated September 15, 1998.)

UARG suggested that NESCAUM agrees with UARG's position on reliability. However, NESCAUM has responded that it does not agree with UARG's position. (See September 1998 NESCAUM letter to EPA.)

SECTION VI. D: Impact on Small Entities

SUMMARY: Commenter supports the position to exclude boilers with generators of 25 MW or smaller in size because it is not cost-effective. A study conducted by SFT, Inc. estimated the cost to comply with a 0.15 lb/mmBtu limit for the commenter's generating units. This study calculated the annual cost to install and operate SCR for boiler #8. Based on a debt service rate of 4.5 percent and an installation date of 2002, the annual cost for this technology is $0.95 million dollars or 2.1 percent of the commenter's projected 1998 revenues. The cost per ton removed is $4,107 which is much greater than the projected cost effectiveness of $1,468/ton for large EGUs and $1,477 for large non-EGUs.

LETTERS: City of Hamilton Ohio (IV-D-74, III-D-65)

RESPONSE: EPA agrees that the cost-effectiveness of controls for small units is less and that the administrative costs for small units without monitors is greater. In the final action,

EPA concludes that small sources do not emit in amounts that significantly contribute to petitioning State's nonattainment or maintenance problems.

SUMMARY: Commenters argued that cost-effectiveness analysis inappropriately relies on region-wide, source category-wide estimates and fails to consider the relative economies or diseconomies inherent in controlling individual EGUs. One commenter maintained the compliance cost impact small facilities inordinately because of lesser economies of scale in relation to large competitors and because many have not yet had to invest in Title IV controls. In addition, the commenter argued that the investment in Title IV controls are worthless because the rule virtually requires the installation of post-emission control technology.

LETTERS: City Utilities of Springfield (MO) (IV-D-93, III-D-20), City of Orville Ohio (IV-D-85)

RESPONSE: EPA recognizes that there can be differences in the cost of implementing controls on various fossil fuel-fired EGUs. The potential cost impacts of differences in boiler characteristics and applicable control technologies have been accounted for in the IPM analysis used by EPA in estimating cost impact of the rule on EGUs. The Agency's small entity screening analysis documents that the rule will not impose a significant impact on most small entities.

EPA disagrees that the rule virtually requires the installation of post-emission control technology. EPA is not imposing specific controls on sources and is in fact providing flexibility so that a source may choose the most cost-effective option, including the addition of control technologies or the purchase of NOx allowances. Title IV controls (such as combustion controls) are not worthless because they can be used in conjunction with post-emission control technology and lead to a reduction in the amount of post combustion control needed (e.g., less SCR catalyst is needed). They also can be used to reduce the amount of NOx allowances that need to be purchased.

SUMMARY: Commenter maintains that EPA's estimate of EGUs cost to comply with the rule are substantially understated. The commenter estimates its own costs to comply will fall within the range of 4-8% of its electricity revenues. The commenter also maintained that it is infeasible to raise its rates to recapture these expenses because it has nearby competitors that will not incur these costs.

LETTERS: City Utilities of Springfield (MO) (IV-D-93, III-D-20)

RESPONSE: EPA agrees that the cost for the commenter to comply with the rule will fall between 4 and 8 percent of annual revenues. EPA estimates that the commenter's most cost efficient response to the section 126 rule would be to implement a mix of technologies and management strategies, including SCR technology. EPA estimates that the commenter's cost is likely to be approximately 5 percent of annual electricity generation revenue. This impact

federal register

Monday
May 11, 1998

Part II

Environmental Protection Agency

40 CFR Parts 51, 76, and 96

Supplemental Notice for the Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Proposed Rule

Exhibit C

equal to or greater than their actual emissions for that quarter.

In terms of NO_X emitters, the RECLAIM program generally requires stationary sources that emit ten or more tons of NO_X annually or which burn any solid fuels to use CEMS to quantify their emissions. Smaller sources have additional monitoring options. Sources that emit four or more tons of NO_X and less than ten tons may use default emission rates. They must demonstrate that these rates are appropriate by monitoring process variables, performing periodic emissions testing, and conducting periodic tune-ups of equipment. The smallest sources in the RECLAIM program (those with annual emissions of less than four tons) may choose to use default emission rates that require less extensive testing and demonstration than those available to the larger sources.

The program's annual report for 1996 concluded that RECLAIM was continuing to meet its emissions reduction goals; an active trading market had developed; and the compliance rate, once it is finalized for the 1996 compliance year, will be in the 85 to 90 percent range.

C. NO_X Budget Trading Program

1. General Provisions

Today's proposed NO_X Budget Trading Rule will be incorporated into the 40 CFR as a new part 96. The subparts of 40 CFR part 96 are described below. The provisions of 40 CFR part 96 will become effective and apply to sources only if a State incorporates 40 CFR part 96 by reference into the State's regulation or adopts regulations that are in accordance with 40 CFR part 96.

a. Purpose. Subpart A of today's proposed NO_X Budget Trading Rule includes Sections describing: To whom the NO_X trading program would apply; the standard requirements for participants in the program (permitting, NO_X allowances, monitoring, excess emissions, and liability provisions); exemptions for retired units from the program requirements; definitions, measurements, and abbreviations; and computation of deadlines stated within the proposal.

b. Definitions, Measurements, Abbreviations, and Acronyms.

Many of the definitions, measurements, abbreviations, and acronyms are the same as those used in 40 CFR part 72 of the Acid Rain Program regulations, in order to maintain consistency among programs. However, additional terms specific to the NO_X Budget Trading Program, such as control period (the period beginning May 1 of each year and ending on September 30 of the same year), NO_X Budget unit (a unit subject to the emissions limitation under the NO_X Budget Trading Program), and several others are added. Key definitions are discussed in relevant Sections below describing the rule.

c. Applicability. The EPA proposes that the NO_X Budget Trading Rule be applicable to a core group of sources that includes all fossil fuel-fired, stationary boilers, combustion turbines, and combined cycle systems (i.e., "units") that serve an electrical generator of capacity greater than 25 MWe and to any fossil fuel-fired, stationary boilers, combustion turbines, and combined cycle systems not serving a generator that have a heat input capacity greater than 250 mmBtu/hr. A unit is considered fossil fuel-fired if fossil fuels account for more than 50 percent of the unit's heat input on an annual basis. These sources represent about 80 percent of the point source portion of the 2007 NO_X baseline emissions inventory and about 65 percent of the point source portion of the 2007 NO_X budget in the proposed ozone transport rulemaking. Additionally, these sources represent about 90 percent of the emissions reductions required in the proposed ozone transport rulemaking.

The EPA proposes the above core group of sources based on their significant contribution of NO_X emissions, range of cost-effective emissions reduction options, ability to monitor emissions, and ability to identify responsible parties. The following discussion examines the monitoring and responsible party criteria for the NO_X Budget Trading Program's applicability. Additional options for the trading program's applicability are also presented for consideration. The EPA solicits comment on the appropriateness of including all categories described above in the core group of sources, whether the size cut-offs should be higher or lower for these source categories, and the appropriateness of including other source categories in the core group.

i. Monitoring. In general, sources that participate in a cap-and-trade program must have the ability to accurately and consistently account for their emissions. Accuracy is an important design parameter because it ensures that emissions for all sources covered by the trading program are within the cap. In addition, because each NO_X allowance will have economic value, it is important to ensure that emissions (and thus allowances used) are accurately quantified. Consistency is an important feature because it ensures that accuracy is maintained from source to source and year to year. It also ensures that the sources in the trading program are treated equitably. Finally, consistency facilitates administration of the program for both the regulated community and State and Federal agencies.

When considering what source types to include in the proposed trading program (e.g., large boilers, process sources, mobile sources, area sources), EPA determined that the core sources were capable of accurate and consistent monitoring as outlined below.

- Large Electric Utility Units: For several years, units serving electricity generators greater than 25 MWe (with some exemptions for cogeneration and nonutility electricity generating units) have been complying with the title IV monitoring provisions. The EPA proposes to include these sources in the NO_X Budget Trading Program.
- Other Large Electricity Generating Units: Additionally, with deregulation of electric utilities, it is not clear how ownership of the electricity generating facilities will evolve. Therefore, EPA proposes to include all large electricity generating sources, regardless of ownership, in the trading program. As there is no relevant physical or technological difference between utilities and other power generators, the same monitoring provisions and the size cut-off of greater than 25 MWe are applicable to all units which serve generators.
- Other Large Steam Producing Units: There is also no fundamental physical or technological difference between a boiler, combustion turbine, or combined cycle system that produces steam for eventual production of electricity or for other industrial applications. Thus, EPA believes that the same monitoring provisions can be applied to a boiler, combustion turbine, or combined cycle system used for industrial steam.[13]

ii. Responsible Party. Another critical element of a trading program is to be able to identify a responsible party for each regulated source. The responsible party for a source covered by the trading program would be required to demonstrate compliance with the provisions of the NO_X Budget Trading Program. In general, the large sources included in the proposed trading program have readily identifiable owners and operators that would serve as the responsible party.

[13] Further, assuming a generator efficiency of approximately ⅓, the 25 MWe cutoff being used for electrical power producers is roughly equal to a 250 mmBtu/hr cutoff for steam producing boilers, combustion turbines, and combined cycle systems.

Commander, no person or vessel may enter or remain in the regulated area.

Regulatory Evaluation

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866 and does not require an assessment of potential costs and benefits under section 6(a)(3) of that order. It has been exempted from review by the Office of Management and Budget under that order. It is not significant under the regulatory policies and procedures of the Department of Transportation (DOT) (44 FR 11040; February 26, 1979). The Coast Guard expects the economic impact of this rule to be so minimal that a full Regulatory Evaluation under paragraph 10e of the regulatory policies and procedures of DOT is unnecessary. Since the regulations will only be in effect for one hour, the impacts on routine navigation are expected to be minimal.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), the Coast Guard must consider whether this rule will have a significant economic impact on a substantial number of small entities. "Small entities" include independently owned and operated small businesses that are not dominant in their field and that otherwise qualify as "small business concerns" under section 3 of the Small Business Act (15 U.S.C. 632). Because it expects the impact of this rule to be minimal, the Coast Guard certifies under 5 U.S.C. 605(b) that this temporary final rule will not have a significant economic impact on a substantial number of small entities.

Collection of Information

These regulations contain no collection of information requirements under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

Federalism

The Coast Guard has analyzed this rule under the principles and criteria contained in Executive Order 12612 and has determined that this rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

Environment

The Coast Guard considered the environmental impact of this rule and concluded that, under figure 2–1, paragraph (34)(h) of COMDTINST M16475.1C, this rule is categorically excluded from further environmental documentation. Special local regulations issued in conjunction with a regatta or marine parade are excluded under that authority.

List of Subjects in 33 CFR Part 100

Marine Safety, Navigation (water), Reporting and recordkeeping requirements, Waterways.

Temporary Regulations

In consideration of the foregoing, Part 100 of Title 33, Code of Federal Regulations is amended as follows:

PART 100—[AMENDED]

1. The authority citation for Part 100 continues to read as follows:

Authority: 33 U.S.C. 1233; 49 CFR 1.46 and 33 CFR 100.35.

2. A temporary section 100.35–T05–106 is added to read as follows:

§ 100.35–T05–106 Cape Fear River, Wilmington, North Carolina.

(a) *Definitions:*

(1) *Regulated Area.* The waters of the Cape Fear River from shoreline to shoreline, bounded on the north by a line drawn along latitude 34°14.4′ North and bounded on the south by a line drawn along latitude 34°14.0′ North. All coordinates reference Datum NAD 1983.

(2) *Coast Guard Patrol Commander.* The Coast Guard Patrol Commander is a commissioned, warrant, or petty officer of the Coast Guard who has been designated by the Commander, Coast Guard Group Fort Macon.

(b) *Special Local Regulations:*

(1) Except for persons or vessels authorized by the Coast Guard Patrol Commander, no person or vessel may enter or remain in the regulated area.

(2) The operator of any vessel in this area shall:

(i) Stop the vessel immediately when directed to do so by any official patrol, including any commissioned, warrant, or petty officer on board a vessel displaying a Coast Guard ensign.

(ii) Proceed as directed by any official patrol, including any commissioned, warrant, or petty officer on board a vessel displaying a Coast Guard ensign.

(c) *Effective Dates.* This temporary final rule is effective from 11:30 p.m. on December 31, 1998 to 12:30 a.m. on January 1, 1999.

Dated: December 8, 1998.

Roger T. Rufe, Jr.,

Vice Admiral, U.S. Coast Guard Commander, Fifth Coast Guard District.

[FR Doc. 98–34133 Filed 12–23–98; 8:45 am]

BILLING CODE 4910–15–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 96

[FRL–6198–1]

Correction and Clarification to the Finding of Significant Contribution and Rulemaking for Purposes of Reducing Regional Transport of Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correction and clarification.

SUMMARY: The EPA is correcting and clarifying certain aspects to the requirements for 22 States and the District of Columbia to submit State implementation plan (SIP) revisions to prohibit specified amounts of emissions of oxides of nitrogen (NO_X) (also referred to as the NO_X SIP call). Most importantly, EPA is reopening the period for emissions inventory revisions to 2007 baseline sub-inventory information used to establish each State's budget in the NO_X SIP Call to February 22, 1999. This includes source-specific emission inventory data and vehicle miles traveled (VMT) and nonroad mobile growth rates, VMT distribution by vehicle class, average speed by roadway type, inspection and maintenance program parameters, and other input parameters used in the calculation of highway vehicle emissions. The comment period for 2007 baseline sub-inventory revisions will be reopened for two related notices of proposed rulemaking concerning Clean Air Act section 126 petitions (the section 126 proposal) and Federal implementation plans for the NO_X SIP call (the FIP proposal) in a future action.

DATES: This rule is effective December 28, 1998.

ADDRESSES: Dockets containing information relating to this rulemaking (docket Nos. A–96–56, A–97–43, and A–98–12) are available for public inspection at the Air and Radiation Docket and Information Center (6102), U.S. Environmental Protection Agency, 401 M Street SW, room M–1500, Washington, DC 20460, telephone (202) 260–7548, between 8:00 a.m. and 4:00 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying. E-mail is A–AND–R–DOCKET–GROUP@EPA.GOV.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to Kimber S. Scavo, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD–15,

Exhibit D

Research Triangle Park, NC 27711, telephone (919) 541-3354; e-mail: scavo.kimber@epa.gov. Specific questions on emissions inventory updates should be directed to Greg Stella, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, MD-14, Research Triangle Park, NC 27711, telephone (919) 541-3649; e-mail: stella.greg@epa.gov.

SUPPLEMENTARY INFORMATION: By notice dated October 27, 1998, EPA published, "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone," 63 FR 57356, which may be referred to as the NO_X SIP call. By notice dated September 30, 1998, EPA proposed, "Findings of Significant Contribution and Rulemakings on Section 126 Petitions and Federal Implementation Plans for Purposes of Reducing Interstate Ozone Transport," 63 FR 52213. On October 21, 1998, EPA published longer, more detailed versions of these proposals entitled "Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport," 63 FR 56292, and "Federal Implementation Plans to Reduce the Regional Transport of Ozone," 63 FR 56394. The section 126 proposal and the FIP proposal are related to the final NO_X SIP call. The comment period for these two proposals closed on November 30, 1998.

Emission Inventory Revisions

The EPA has received numerous requests to allow more time to accept revisions to source-specific inventory data used to establish each State's base and budget in the NO_X SIP Call and to also allow revisions to VMT projections. The final SIP call, as described on page 57427, provided that the opportunity for source-specific inventory data revisions would be available for the first 60 days of the 12-month period between signature of the NO_X SIP call and the deadline for submission of the required SIP revisions (i.e., November 23, 1998). The Agency is aware of difficulties some States have had accessing the emission inventory data bases. Therefore, EPA, today, is reopening this time period to 60 days from the date of publication of this rule rather than signature of the NO_X SIP call and to accept revisions to VMT projections. However, the EPA strongly urges commenters to submit proposed changes to the inventories of EGUs greater than 25 MWe and non-EGU boilers and turbines greater than 250 mmBtu/hr within 30 days from the date of publication of this document, i.e., January 25, 1999. The EPA requests commenters submit comments on these sources first in order to facilitate incorporation of any necessary changes into the budgets for the section 126 final rulemaking which must be finalized by April 30, 1999 in accordance with the consent decree governing EPA's action on the pending section 126 petitions. The EPA recommends that commenters also submit suggested inventory revisions to the dockets for the section 126 proposal and the FIP proposal. By a future notification, EPA will reopen the comment period for those proposed actions to February 22, 1999 solely for the purpose of receiving such inventory revisions. Additionally, no changes to the emissions inventory will be made unless information, as specified in Section III.F.5 of the final NO_X SIP call, is provided to corroborate and justify the need for the requested modification. These revisions must be postmarked by February 22, 1999 and sent directly to the Docket Office listed in **ADDRESSES** (in duplicate form if possible). (Docket no. A-96-56 for the NO_X SIP call, A-97-43 for the section 126 proposal, and A-98-12 for the FIP proposal.) Sources and other non-State commenters should also send a copy of their comments concerning the inventory changes to their State air pollution control agency.

Individuals interested in modifications requested by commenters may review the materials as they are submitted and available in the dockets. With respect to the SIP call, within 60 days after the close of this comment period—i.e., by April 23, 1999—EPA will evaluate the data submitted by commenters and, if it is determined to be technically justified, revise the State budgets for the NO_X SIP call to reflect the new data.

For a comment to be considered, the data submitted in the request for modification must be submitted in electronic format (i.e., spreadsheet, data base, text file) and must be accompanied by information to support the requested change. The EPA has identified the specific data elements for each source sector that must be included in the electronic file submitted with any data modification request. For budget calculation purposes, emphasis should be on NO_X emissions, noting that other precursor emissions and modeling data are necessary for final development of the modeling inventory.

However, in many cases, not all of the inventory information needs to be corrected and resubmitted. For example, it may be the case that source-specific NO_X emission rates are incorrect, but all stack and other emissions data are acceptable. In these cases, it is not necessary to resubmit the entire inventory record data. Only source identification information and additional data that require correction need to be resubmitted. In those cases where the majority of the data are incorrect or the submission is for a new, unaccounted for source, complete files with all data fields outlined in Section III.F.5 of the final rulemaking preamble must be submitted.

For those sources so indicated above, a simplified inventory revision submittal is acceptable and must include the following information:

- Source sector needing revision.
- Identification of the specific changes requested to the inventory.
- Reason for requested change.
- All of the following sector-specific information in electronic file format:

Electric Generating Units

Data on a source-specific basis including:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Plant name.
- Plant ID numbers (ORIS code preferred (ORIS is a coding mechanism used by the Department of Energy to track plants with EGUs), State agency tracking number also or otherwise).
- Unit ID numbers (a unit is a boiler or other combustion device).
- Unit type (also known as prime mover; e.g., wall-fired boiler, stoker boiler, combined cycle, combustion turbine, etc.).
- Primary fuel on a heat input basis.
- Maximum rated heat input capacity of unit.
- Nameplate capacity of the largest generator the unit serves.
- 1995 and 1996 ozone season heat inputs.
- 1996 (or most recent) average NO_X rate for the ozone season.

Non-EGU Point Sources

Data on a source-specific basis including:

- Federal Information Placement System State Code.
- Federal Information Placement System (FIPS) County Code.
- Plant name.
- Plant ID numbers (National Emission Data System (NEDS), Aerometric Information Retrieval System/AIRS Facility Subsystem (AIRS/AFS), and State agency tracking number also or otherwise).
- Unit ID numbers.
- Primary source classification code (SCC).

• Maximum rated heat input capacity of unit.
• 1995 ozone season or typical ozone season daily NO_X emissions.
• 1995 existing NO_X control efficiency.

Stationary Area Sources

Data on a sub-category specific basis including:
• Federal Information Placement System State Code.
• Federal Information Placement System (FIPS) County Code.
• Source classification code (SCC).
• 1995 ozone season or typical ozone season daily NO_X emissions.
• 1995 existing NO_X control efficiency.

Nonroad Mobile Sources

Data on a sub-category specific basis including:
• Federal Information Placement System State Code.
• Federal Information Placement System (FIPS) County Code.
• Source classification code (SCC).
• 1995 ozone season or typical ozone season daily NO_X emissions.
• 1995 existing NO_X control efficiency.

Highway Mobile Sources

Data on a SCC or vehicle type basis including:
• Federal Information Placement System State Code.
• Federal Information Placement System (FIPS) County Code.
• Primary source classification code (SCC) or vehicle type.
• 1995 ozone season or typical ozone season daily vehicle miles traveled (VMT).

The EPA is also accepting comments on VMT and nonroad mobile growth rates, VMT distribution by vehicle class, average speed by roadway type, inspection and maintenance program parameters, and other input parameters used in the calculation of highway vehicle emissions. These comments must be on a county-level basis and must include adequate evidence and explanation for any differences between the input parameters used in the final rulemaking budgets and the input parameters being proposed in the comments. Comments also must be consistent with other State submittals, including SIPs, transportation plans and conformity demonstrations, and other documents, or must contain an explanation for the differences between the comments and these other recent submittals and a plan to correct these other submittals to make them consistent with the comments submitted in response to this notice.

This process will not change the timeframes for the FIP (63 FR 56394) or section 126 (63 FR 56292) actions. A courtesy copy of comments mailed to Greg Stella at the address listed above would be appreciated in addition to the formal submittal to the docket(s).

Correction to Table III–1

When EPA published the final SIP call, EPA inadvertently included as Table III–1, a previous version of numbers that do not match the final budget numbers for the SIP call (see 63 FR 57410). The following Table III–1 includes corrected numbers.

TABLE III–1.—STATE BUDGETS BY ENERGY SOURCE BASIS

[Higher of 1995 or 1996 EIA data]

State	Proposed input-based budgets fossil fuel-burning generators	Revised (final) input-based budgets fossil fuel-burning generators	Output-based budgets—all generation sources	Output-based budgets—all generation sources except nuclear	Output-based budgets fossil fuel-burning generators
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Alabama	30644	29051	34949	35186	32854
Connecticut	5245	2583	7703	5173	4471
Delaware	4994	3523	2400	3225	3428
District of Columbia	152	207	100	133	142
Georgia	32433	30255	32331	31819	30922
Illinois	36570	32045	44401	27982	29701
Indiana	51818	49020	32320	43430	45985
Kentucky	38775	36753	24930	33501	34281
Maryland	12971	14807	13329	13013	13256
Massachusetts	14651	15033	11054	13292	13541
Michigan	29458	28165	32383	32145	32566
Missouri	26450	23923	19856	22776	23577
New Jersey	8191	10863	12807	11265	11508
New York	31222	30273	39635	39572	32222
North Carolina	32691	31394	32113	30257	29966
Ohio	51493	48468	39923	47301	50187
Pennsylvania	45971	52000	53629	47172	48639
Rhode Island	1609	1118	2250	3022	3213
South Carolina	19842	16290	23330	14132	13877
Tennessee	26225	25386	26499	26172	24853
Virginia	20990	18258	19155	15753	15619
West Virginia	24045	26439	22930	30811	32636
Wisconsin	17345	17972	15798	16693	16379
Total	563785	543825	543825	543825	543825

Budget Reductions for Large EGUs and Non-EGUs

The 2007 baseline inventory for large EGUs and non-EGUs is based on the universe of sources in the 1995 inventory and a growth factor which accounts both for increases in use of those sources and for new sources that commence operation after 1995. As explained in the October 27, 1998, NO_x SIP Call and as further clarified later in today's notice, the final State budgets cap emissions on all large EGUs and non-EGUs. This includes both sources that operated in 1995 and were part of the baseline inventory and new sources that commence operation after 1995. Since States must implement emission reduction strategies that either cap emissions from these sources at the levels specified in the SIP Call budgets or achieve equivalent reductions, all boilers and turbines must be classified as either EGUs or non-EGUs and as small or large. In this notice, EPA reiterates how boilers and turbines that existed in 1995 were classified. As explained above, EPA will be finalizing a revised 1995 inventory based on additional comments received. The classifications that EPA uses in this inventory are the ones that EPA will use in 2007 to determine if a unit should be included in the EGU or non-EGU portion of this budget. This notice also clarifies how EPA will classify units that commence operation after 1995.

Clarification of EGU Classification for Purposes of Estimating Budget Reductions

The following discussion clarifies EPA's classification of units as EGUs. This clarification also applies to the proposed FIP and the EPA action under section 126.[1]

Consistent with the supplemental notice of proposed rulemaking (63 FR 25902, May 11, 1998) and the accompanying technical support document related to budget development, EPA took a two-step approach to determining which of the following categories a boiler or turbine fit into: large EGU, small EGU, large non-EGU or small non-EGU. First, EPA determined if a boiler or turbine fit into the category of EGU or non-EGU. The EPA then determined if the boiler should be classified as large or small.

The EPA used three sources of data for determining if a generator's purpose included generation of electricity for sale and thus qualified the unit connected to the generator as an EGU. First, EPA treated as EGUs all units that are currently reporting under Title IV of the Clean Air Act. Second, EPA included as EGUs any additional units that were serving generators reporting to the Energy Information Administration (EIA) using Form 860 in 1995. Form 860 is submitted for utility generators. Third, EPA included units serving generators that reported to EIA using Form 867 in 1995. Since Form 867 is submitted by non-utility generators, including generators "which consume all of their generation at the facility," EPA excluded any units for which EPA had information indicating that the unit was not connected to any generators that sold any electricity. This was primarily determined by excluding units that were not listed as sources that sell power under contract to the electric grid using the electric generation forecasts of the North American Electric Reliability Council.

Once EPA determined that a boiler or turbine should be classified as an EGU, EPA considered that unit a large EGU if it served a generator greater than 25 MWe and considered it a small EGU if it served a generator less than or equal to 25 MWe.

While EPA believes that this methodology was the best way to classify existing boilers and turbines given the data available, EPA does not believe that this is the best way to classify new boilers or turbines for regulatory purposes. The EPA will continue to use this methodology to classify units that operated on or before December 31, 1995 as EGUs or non-EGUs. Any requests to change the EGU/non-EGU categorization of a unit operating on or before December 31, 1995 that EPA has categorized as an EGU or a non-EGU or any requests to add a unit operating on or before December 31, 1995 that has not been categorized as an EGU or a non-EGU should follow the methodology based on data reported to EPA and EIA, outlined above. Once EPA responds to comments received, EPA does not intend to reclassify units that were in operation before January 1, 1996 because, as discussed below, EPA uses a different approach to classify units that commence operation on or after January 1, 1996. However, EPA may reconsider unit classifications in 2007 along with the 2007 transport reassessment.

The EPA believes there are two important reasons that the methodology outlined above is not appropriate to use on an ongoing basis for new boilers or turbines. First, EPA is concerned about the completeness of data using this methodology. The EPA has this concern because there are limited consequences to not reporting to EIA and because EPA has no assurance that sources will continue to be required to report to EIA using the same forms. Second, because of changes in the electric generation industry and because of regulatory developments such as the SIP call, owners and operators of units may have an incentive to install small (25 MWe or less) generators to larger boilers or turbines that are primarily used for industrial processes and not electricity generation. Such sources should be considered large and be controlled.

For units commencing operation on or after January 1, 1996, EPA plans to use the following two-step process. First, EPA intends to classify as an EGU any boiler or turbine that is connected to a generator greater than 25 MWe from which any electricity is sold. This will be based on information reported directly to the State under the SIP (or EPA in the case of a FIP or section 126 action). The EPA believes this addresses the first concern about completeness of data, as discussed in the previous paragraph. Second, if a boiler or turbine is connected to a generator equal to or less than 25 MWe from which any electricity is sold, it will be considered a small EGU if it has the potential to use more than 50.0 percent of the usable energy from the boiler or turbine to generate electricity. This will address EPA's second concern (discussed in the previous paragraph) about owners or operators of large boilers and turbines that have small generators. All other boilers and turbines (including boilers and turbines connected to generators equal to or less than 25 MWe from which any electricity is sold and which have the potential to use 50.0 percent or less of the usable energy from the boiler or turbine to generate electricity) will be considered non-EGUs and the process described below should be used to classify those units as large or small. Once a unit has been classified, EPA does not intend to reclassify that unit, but may reconsider unit classification in 2007 along with the 2007 transport reassessment.

Clarification of Non-EGU Large Source Classification for Purposes of Estimating Budget Reductions

The following discussion clarifies EPA's classification of "large" and "small" sources for categories of the non-EGU point sources affected by the emissions budget reductions. The "large" non-EGU point source categories involved in the budget reductions are boilers, turbines, stationary internal combustion engines, and cement plants. The following method was used to

[1] If any comments are received on the following EGU classification, EPA will consider them in the context of its final section 126 and FIP actions.

identify "large" and "small" non-EGU boilers and turbines (for more detailed information refer to the "Development of Modeling Inventory and Budgets for Regional SIP Call" document, September 24, 1998, in docket A-96-56):

1. Where boiler heat input capacity data were available for a unit, those data were used. Units with such data that are less than or equal to 250 mmBtu are "small" and units greater than 250 mmBtu/hr are "large."

2. Where boiler heat input capacity data were not available for a unit, those data were estimated, as described in the NPR and SNPR. Units estimated to be greater than 250 mmBtu/hr are "large."

3. Where boiler heat input capacity data were not available for a unit and where the boiler capacity was estimated to be less than 250 mmBtu/hr, 1995 point-level emissions were checked for each unit. If the 1995 average daily ozone season emissions were greater than one ton, the unit was categorized as a "large" source; otherwise, the unit was categorized as a "small" source.

A stationary internal combustion engine and a cement plant were determined to be "large" if its 1995 average daily ozone season emissions were greater than one ton. The heat input capacity does not affect its classification as large or small.

Clarification to 40 CFR 51.121(f)(2)(ii)

This notice clarifies that 40 CFR 51.121(f)(2)(ii) requires that if a State controls large EGUs and large non-EGU boilers, turbines and combined cycle units for purposes of complying with the NO_X SIP call, those control measures must assure that collectively all such sources, including new or modified units, will not exceed the total NO_X emissions projected for such sources and that those control measures must be in place no later than May 1, 2003. The amendment made to 40 CFR 51.121(f)(2)(ii) in this correction notice also clarifies that if SIP rules allow the large EGUs and large non-EGU boilers, turbines, and combined cycle units to use credits from the State compliance supplement pool, those units may use credit from the State compliance supplement pool during the 2003 or 2004 control seasons.

Section 51.121(f)(2)(ii) in the October 27 final SIP call requires that if a State elects to impose control measures on fossil fuel-fired NO_X sources serving electric generators with a nameplate capacity greater than 25 MWe or boilers, combustion turbines or combined cycle units with a maximum design heat input greater than 250 mmBtu/hr, those measures must assure that collectively all such sources, including new or modified units, will not exceed in the 2007 ozone season the total NO_X emissions projected for such sources. Section 51.121(b)(1)(i) requires that SIP revisions must contain control measures adequate to prohibit NO_X emissions in excess of the budget for that jurisdiction and 40 CFR 51.121(b)(1)(ii) requires that those control measures be implemented by May 1, 2003. Therefore, 40 CFR 51.121(f)(2)(ii) is amended to contain an explicit reference to 40 CFR 51.121(b)(1)(i) and (ii). This amendment clarifies that the control measures adopted for large EGUs and large non-EGU boilers, turbines, and combined cycle units sources, including new or modified units, must be in place by May 1, 2003."

Additionally, by referencing 40 CFR 51.121(b)(1)(i) (40 CFR 51.121(b)(1)(i) references 40 CFR 51.121(e) which provides for distribution of the compliance supplement pool) in 40 CFR 51.121(f)(2)(ii), this notice clarifies that if SIP rules allow large EGUs and large non-EGU boilers, turbines and combined cycle units to use credits from the State compliance supplement pool, those sources, including new or modified units, may demonstrate compliance in the 2003 and 2004 control seasons using credit from the compliance supplement pool.

Correction to 40 CFR 96.42

This notice corrects the formula for distributing unused allowances in the new source set-aside back to existing sources. The October 27 final SIP call mistakenly included an extra parenthesis in the text of 40 CFR 96.42. The text of 40 CFR 96.42 is corrected to remove the extra parenthesis so that the formula reads: Unit's share of NO_X allowances remaining in allocation set-aside = Total NO_X allowances remaining in allocation set-aside × (Unit's NO_X allowance allocation ÷ State trading program budget excluding allocation set-aside).

Correction to Page 57,404

On page 57,404, third column, the carryover sentence, beginning, "The Air Quality Modeling TSD * * *" is inaccurate and is replaced with the following: "The 'National Air Quality and Emissions Trends Report, 1996,' included in the docket as VI-C-18, contains information as to the reductions in ozone values that have resulted from these controls."

Administrative Requirements

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and is therefore not subject to review by the Office of Management and Budget. In addition, this action does not impose any enforceable duty, contain any unfunded mandate, or impose any significant or unique impact on small governments as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104-4). This action also does not require prior consultation with State, local, and tribal government officials as specified by Executive Order 12875 (58 FR 58093, October 28, 1993) or Executive Order 13084 (63 FR 27655 (May 10, 1998), or involve special consid[illegible]ation of environmental justice relate[illegible] required by Executive Ord[illegible]9, February 16, 199[illegible] not subject to [illegible] u[illegible] [illegible] C.

(F[illegible] Environm[illegible] Safety Risks) (62 FR 19[illegible] 97) because EPA interprets [illegible] 45 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5-501 of the Order has the potential to influence the regulation. This action is not subject to E.O. 13045 because it does not establish an environmental standard intended to mitigate health or safety risks. In addition, the National Technology Transfer and Advancement Act of 1997 (NTTAA) does not apply because today's action does not require the public to perform activities conducive to the use of voluntary consensus standards under that Act. The EPA's compliance with these statutes and Executive Orders for the underlying rule, the final NO_X SIP call, is discussed in 63 FR 57477-81 (October 27, 1998).

List of Subjects

40 CFR Part 51

Environmental protection, Air pollution control, Administrative practice and procedure, Carbon monoxide, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Transportation, Volatile organic compounds.

40 CFR Part 96

Environmental protection, Administrative practice and procedure, Air pollution control, Nitrogen dioxide, Reporting and recordkeeping requirements.

Dated: December 18, 1998.

Robert Perciasepe,

Assistant Administrator for Air and Radiation.

40 CFR parts 51 and 96 are amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart G—Control Strategy [Amended]

2. Section 51.121 is amended to revise paragraphs (e)(4) introductory text and (f)(2)(ii) to read as follows:

§ 51.121 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen.

* * * * *

(e) * * *

(4) If, no later than February 22, 1999, any member of the public requests revisions to the source-specific data and vehicle miles traveled (VMT) and nonroad mobile growth rates, VMT distribution by vehicle class, average speed by roadway type, inspection and maintenance program parameters, and other input parameters used to establish the State budgets set forth in paragraph (e)(2) of this section or the 2007 baseline sub-inventory information set forth in paragraph (g)(2)(ii) of this section, then EPA will act on that request no later than April 23, 1999 provided:

* * * * *

(f) * * *

(2) * * *

(ii) Impose enforceable mechanisms, in accordance with paragraphs (b)(1) (i) and (ii) of this section, to assure that collectively all such sources, including new or modified units, will not exceed in the 2007 ozone season the total NO_X emissions projected for such sources by the State pursuant to paragraph (g) of this section.

* * * * *

PART 96—NO_X BUDGET TRADING PROGRAM FOR STATE IMPLEMENTATION PLANS

3. The authority citation for part 96 continues to read:

Authority: U.S.C. 7401, 7403, 7410, and 7601.

4. Section 96.42 is amended in paragraph (f) to revise the formula immediately preceding the word "Where:" to read as follows:

§ 96.42 NO_X allowance allocations.

* * * * *

(f) * * *

Unit's share of NO_X allowances remaining in allocation set-aside = Total NO_X allowances remaining in allocation set-aside × (Unit's NO_X allowance allocation ÷ State trading program budget excluding allocation set-aside)

* * * * *

[FR Doc. 98–34150 Filed 12–23–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 266 and 273

[FRL–6207–7]

RIN 2050–AD19

Universal Waste Rule (Hazardous Waste Management System; Modification of the Hazardous Waste Recycling Regulatory Program)

AGENCY: Environmental Protection Agency.

ACTION: Final rule; correcting amendments.

SUMMARY: The Environmental Protection Agency (EPA) is correcting errors that appeared in the Universal Waste Rule which was published in the **Federal Register** (FR) on May 11, 1995 (60 FR 25492). This final rule creates no new regulatory requirements; rather it: makes three corrections to the regulations governing management of spent lead-acid batteries that are reclaimed; corrects the definition of a small quantity universal waste handler; and clarifies the export requirements which apply to destination facilities when destination facilities act as universal waste handlers.

EFFECTIVE DATE: December 24, 1998.

FOR FURTHER INFORMATION CONTACT: For general information, contact the RCRA/Superfund Hotline at (800) 424–9346 (toll free) or TDD 800 553–7672 (hearing impaired). Contact the RCRA Hotline in the Washington, D.C. metropolitan area at (703) 412–9810 or TDD 703 412–3323. For specific information concerning the Universal Waste Rule, contact Mr. Bryan Groce at (703) 308–8750, Office of Solid Waste, U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, mailcode 5304W. This rule is available on the Internet. Please follow these instructions to access the rule electronically: From the World Wide Web (WWW), type://www.epa.gov/epaoswer, then select option for Laws and Regulations. The official record for this action is kept in a paper format.

SUPPLEMENTARY INFORMATION:

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6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[FRL-XXXX-X]

Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In accordance with section 126 of the Clean Air Act (CAA), EPA is taking final action on petitions filed by eight Northeastern States seeking to mitigate what they describe as significant transport of one of the main precursors of ground-level ozone, nitrogen oxides (NOx), across State boundaries. Each petition specifically requests that EPA make a finding that NOx emissions from certain stationary sources emit in violation of the CAA's prohibition on emissions that significantly contribute to ozone nonattainment problems in the petitioning State. If EPA makes such a finding, EPA is authorized to establish Federal emissions limits for the sources. The eight Northeastern States that filed petitions are Connecticut, Maine, Massachusetts, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont.

Today, EPA is making final determinations that portions of six of the petitions are technically meritorious. The technically approvable portions of the petitions will be automatically deemed granted or denied at certain later dates pending certain actions by the States and EPA regarding State submittals in response to the final NOx State implementation plan call (NOx SIP call). This rule describes the schedule and conditions under which applicable final findings on the petitions would be automatically triggered.

The EPA intends to implement the section 126 control remedy through a Federal NOx Budget Trading Program. The trading program would apply to sources in the source categories for which a final finding is ultimately granted. In today's rule, EPA is finalizing the general parameters of the trading program. The EPA is committing to promulgate the details of the trading program by July 15, 1999. The

Exhibit E

below. The EPA's rationale for determining that large EGU boilers and turbines and large non-EGU boilers and turbines contribute significantly is explained in Section II.J below.

1. Proposed EGU Source Classification

The section 126 NPR proposed the same two-step approach as used in the final NOx SIP call for determining which of the following categories a boiler or turbine fits into: large EGU, small EGU, large non-EGU, or small non-EGU. In the final NOx SIP call, EPA first determined if a boiler or turbine should be classified into the category of EGU or non-EGU. The EPA then determined if the boiler or turbine should be classified as large or small.

The EPA used three sources of data for determining if an existing generator's purpose included generation of electricity for sale and thus qualified the unit connected to the generator as an EGU. First, EPA treated as EGUs all units that are currently reporting under title IV of the CAA. Second, EPA included as EGUs any additional units that were serving generators reporting to the Energy Information Administration using Form 860 in 1995. Form 860 is submitted for utility generators. Third, EPA included units serving generators that reported to Energy Information Administration using Form 867 in 1995. Since Form 867 is submitted by non-utility generators, including generators "which consume all of their generation at the facility," EPA excluded any units for which EPA had information indicating that the unit was not connected to any generators that sold any electricity. This was determined by excluding units that were not listed as sources that sell power under contract to the electric grid using the electric generation forecasts of the North American Electric Reliability Council.

Once EPA determined that a boiler or turbine should be classified as an EGU, EPA considered that unit to be a large EGU if it served a generator greater than 25 MWe and considered it a small EGU if it served a generator less than or equal to 25 MWe.

The EPA explained that there are two important reasons that the methodology outlined above is not appropriate to use on an ongoing basis for new boilers or turbines. First, EPA was concerned about the completeness of data using this methodology. The EPA had this concern because there are limited consequences to not reporting to Energy Information Administration and because EPA has no assurance that sources will continue to be required to report to Energy Information

Administration using the same forms. Second, because of changes in the electric generation industry and because of regulatory developments such as the NOx SIP call, owners and operators of units may have an incentive to install, operate and sell electricity from small (25 MWe or less) generators connected to larger boilers or turbines that are primarily used for industrial processes and not electricity generation. Such sources could have significant NOx emissions.

To ensure that owners and operators of such units did not install a small generator and sell small amounts of electricity merely to circumvent the requirements of this rule, EPA established a slightly different process for categorizing units that commenced operation on or after January 1, 1996. First, EPA explained it would classify as an EGU any boiler or turbine that is connected to a generator greater than 25 MWe from which any electricity is sold. This would be based on information reported directly to the State under the SIP (or EPA in the case of a FIP or section 126 action). The EPA stated that this addresses the first concern about completeness of data, as discussed in the previous paragraph. Second, if a boiler or turbine is connected to a generator equal to or less than 25 MWe from which any electricity is sold, it would be considered a small EGU if it has the potential to use more than 50.0 percent of the usable energy from the boiler or turbine to generate electricity. For example, this means that a 260 mmBtu boiler connected to a 20 MWe generator that is used to generate some electricity for sale would be considered a small EGU. On the other hand, a 600 mmBtu boiler connected to a 20 MWe generator that is used to generate some electricity for sale would be considered a large non-EGU. This addressed EPA's second concern (discussed in the previous paragraph) about owners or operators of large boilers and turbines that have small generators.

All other boilers and turbines (including boilers and turbines connected to generators equal to or less than 25 MWe from which any electricity is sold and which have the potential to use 50.0 percent or less of the usable energy from the boiler or turbine to generate electricity) were considered non-EGUs. The EPA stated that it will use the process described below to classify those units as large or small. The EPA stated that, once a unit had been classified in the base inventory, EPA did not intend to reclassify that unit, but explained that it might reconsider unit classification in 2007 along with the 2007 transport

reassessment.

2. Proposed Non-EGU Boiler and Turbine Source Classification

In the section 126 NPR, the non-EGU point source categories that EPA determined to be subject to the section 126 reduction requirements are large boilers and turbines. The EPA proposed in the section 126 NPR to use the same method to identify "large" and "small" non-EGU boilers and turbines that was used in the final NOx SIP call (for more detailed information refer to "Development of Modeling Inventory and Budgets for Regional SIP Call," September 24, 1998). The methodology is as follows:

1. Where boiler heat input capacity data were available for a unit, EPA used that data. Units with such data that are less than or equal to 250 mmBtu are "small" and units greater than 250 mmBtu/hr are "large."
2. Where boiler heat input capacity data were not available for a unit, EPA estimated that data, as described in the NOx SIP call NPR and SNPR. Units estimated to be greater than 250 mmBtu/hr are "large."
3. Where boiler heat input capacity data were not available for a unit and where the boiler capacity was estimated to be less than 250 mmBtu/hr, EPA checked 1995 point-level emissions for each unit. If the 1995 average daily ozone season emissions were greater than one ton, the unit was categorized as a "large" source; otherwise, the unit was categorized as a "small" source.

3. Issues Raised by Commenters on EGU/Non-EGU Classification

One commenter, representing the pulp and paper industry, argued that small cogeneration units should not be treated as EGUs and EPA should continue to apply the exemption from treatment as utility units established under new source performance standards (NSPS) and the Acid Rain Program for cogeneration units that produce an annual amount of electricity for sale less than one-third of their potential electrical output capacity or equal to or less than 25 MWe. (Note that the regulations implementing title IV converted the annual 25 MWe threshold to 129,000 MWe hrs of electricity which is equivalent to 25 MWe per hour times 8760 hours per year.) The commenter also noted that section 112 of the CAA defines "electricity steam generating unit" excluding cogeneration units using the

same thresholds. The commenter made several assertions to support its argument. First, the commenter said the classification of small cogeneration units would be contrary to 20 years of Agency precedent under the NSPS and Acid Rain programs. The CAA encourages cogeneration by exempting small cogenerators below the one-third/25 MWe trigger from the Acid Rain program and from section 112. Deviating from this historical precedent was not a logical outgrowth of the proposed NOx SIP call since the proposed NOx SIP call did not discuss that EPA would treat small cogeneration units as EGUs or differently than under the NSPS and Acid Rain programs. Second, the commenter argued the uniqueness of boiler design, fuel type, and operations of individual industrial boilers makes these units less amenable to achieving the utility standards.

Another commenter expressed concerns that defining "electrical generating units solely on the basis of electrical generating capacity without regards to boiler size is patently unfair to a number of industrial boilers." They explained that "from a practical standpoint, emissions from a 250 mmBTU/hr coal-fired industrial boiler are the same whether it is used to generate electrical power or not." The commenter continued that EPA should treat all industrial boilers alike whether or not they generate electrical power.

Several other commenters expressed concerns that the definition in the trading rule was more inclusive than the definition used for setting forth the control requirements. One commenter suggested specific language to remedy this concern.

As EPA explained in a clarification notice published on December 24, 1998 (See 63 FR at 71223), EPA used two classification methods to determine whether a unit should be classified as an EGU or a non-EGU. One method (based on whether a unit served a generator from which electricity was sold under a firm contract) applied to units that were in existence in 1995 and were part of the base year emission inventory, and the other method (based on whether a unit serves a generator from which any electricity is sold) applies to units that came into existence on or after January 1, 1996. Both of these methodologies are explained above (in sections II.I.C1 and C.2). In addition, the methodology used to classify units in the base-year inventory was explained in the document, "Development of Modeling Inventory and Budgets for Regional NOx SIP call." A draft of this document was issued on March

23, 1998 and a final document was issued on September 24, 1998, and is available in the NOx SIP call docket.

The methodology used to classify existing units as EGUs or non-EGUs was based upon whether or not a unit was connected to a generator that produced electricity for sale under firm contract to the grid. Since most industrial units are not currently involved in sales under firm contract to the grid, this leads to most industrial cogeneration units being classified as non-EGUs. The EPA has several concerns about changing from this methodology to a methodology based upon a one-third potential capacity/25 MWe threshold, as suggested by the commenter. The first is that EPA has not used that threshold in the rulemaking to date, and does not have information on all existing units necessary to apply that threshold to all the units. For example, EPA does not have information to identify all the units that actually cogenerate and the information on how much electricity is sold from these units. The commenter did not even identify the units owned by its members, much less provide that information for identified units.

Second, if EPA did have the information for each unit to determine if the unit's classification should be changed, EPA is concerned that the classification for a number of units would change, apparently none of which are owned or operated by the commenter's members. The commenter noted that changing the definition to be based upon a one-third potential capacity/25 MWe threshold "would not alter the Agency's baseline emissions inventory." Since the commenter never identified any existing units where classification is different in the inventory under the Agency's classification method than under the commenter's classification method, EPA concludes that changing the methodology would not change the inventory classification of any units owned or operated by the commenter's members. The EPA believes that this is because using the criteria of selling under firm contract to the grid classifies most industrial units that generate small amounts of electricity as non-EGUs rather than EGUs.

However, EPA maintains that there is the potential that a number of other units could be reclassified if EPA applied the one-third potential capacity/25 MWe threshold. This could change the classification of a large EGU to a large non-EGU, the classification of a large non-EGU to a large EGU or the classification of a small EGU to a large non-EGU. For example, a unit that

is currently classified as a large EGU could become a large non-EGU if, even though the unit was selling electricity under a firm contract, it sold less than one third of its potential electrical output capacity. An independent power producer unit that is connected to a generator greater than 25 MWe and that cogenerates and provides both steam and electricity could fit into this category. A unit that is currently classified as a large non-EGU could become a large EGU if it did not sell power under a firm contract, but did sell more than one third of its potential electrical output capacity. An industrial boiler that cogenerates and is connected to a generator greater than 25 MWe could fit into this category. A unit that is currently classified as a small EGU and sells under firm contract, but less than one-third of its potential electrical output capacity, could become a large non-EGU if the unit was greater than 250 mmBtu and the generator to which it was connected was less than 25 MWe. An independent power producer unit that cogenerates could fit into this category. In short, the adoption of the commenter's classification methodology could result in reclassification leading to more stringent, rather than less stringent, regulation of some cogeneration facilities

The EPA also does not agree with the commenter's arguments: (1) that deviating from the classification that EPA has used for cogeneration units for 20 years was not a logical outgrowth of the proposed NOx SIP call and that no discussion was included in the proposal that small cogeneration units would be treated as EGUs or differently than under the NSPS and Acid Rain programs; or (2) that the uniqueness of boiler design, fuel type, and operations of individual industrial boilers makes these units less amenable to achieving the reduction requirements for large EGUs.

In prior regulatory programs, EPA has used the criteria of producing an annual amount of electricity for sale less than one-third of a unit's potential electrical output capacity or less than 25 MWe. However, these criteria were not applied in the same way in each of these prior programs and recent, ongoing changes in the electric power industry undermine the basis for the criteria, and justify using different criteria for the new units, in today's action. The Agency began using the one-third potential capacity/25MWe cutpoint in 1978, in 40 CFR part 60, subpart Da, setting forth new source performance standards for "electric utility steam generating

units." In that case, the cutpoint was not used to exempt units entirely from NSPS. Rather, it was used to classify them as either "electric utility steam generating units" that would be subject to the new standards under subpart Da or to classify them as non-utility steam generating units that would continue to be subject to the requirements under subpart D and would subsequently become subject to more stringent standards for "Industrial-Commercial-Institutional Steam generating units" under subpart Db. As the commenter noted, this distinction between utility and non-utility units continued under the Clean Air Act Amendments of 1990, in both title IV and section 112. This cutpoint applied to all steam generating units, not just cogeneration facilities. The cutpoint was used as a proxy for utility vs. non-utility ownership of the units, the assumption being that a unit involved in electricity sales at or below the cutpoint was owned by a company that was in a business other than electric generation and so was a utility.

Since 1990 there have been dramatic changes in the electric power industry associated with the emergence of competitive markets for electricity generation where non-utility generators compete to an increasingly significant extent with traditional utilities. As these changes occur, it becomes less and less appropriate to differentiate between utilities and non-utilities that produce electricity. The Energy Policy Act of 1992 reflected these types of changes in the electric power industry by recognizing a whole new category of non-utility generators, wholesale generators that directly compete with utility generators. The Federal Energy Regulatory Commission's 1996 order adopting open transmission access and the actions of many States (currently at least 18 States) that are in the process of deregulating electric power generation have further blurred the distinction between utilities and non-utilities. Other federal agencies that deal with the power industry have realized that historical categorizations of the industry are no longer appropriate. For instance, the Energy Information Agency is in the process of streamlining its reporting requirements so that there will no longer be a distinction between reporting by utility generators and by non-utility generators.

In the NOx SIP call rulemaking, that EPA expressed concern that, under a deregulated electricity market, it is important to consider all NOx emissions sources that generate electricity. For instance, in the

supplemental notice of proposed rulemaking under the NOx SIP call, EPA explained that:

> Additionally, with deregulation of electric utilities, it is not clear how ownership of the electricity generating facilities will evolve. Therefore, EPA proposes to include all large electricity generating sources, regardless of ownership, in the trading program. As there is no relevant physical or technological difference between utilities and other power generators, the same monitoring provisions and the size cut-off of greater than 25 MWe are applicable to all units which serve generators. 63 FR at 25923.

With regard to the feasibility of meeting the "utility" standards, the above commenter made several technical arguments about why non-utility units are fundamentally different from utility sources. In particular, the commenter argued that because of the need to vary loads significantly, many industrial boilers cannot operate at the conditions required to obtain maximum NOx reduction using combustion controls. In addition, the commenter argued that pulp and paper mill boilers have technical limitations on the installation of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), due to wide and rapid load and lower operating temperatures. Furthermore, the commenter does not believe there will be a significant number of allowances available or that the assumption of allowance availability should be used to justify higher costs for industrial sources. Moreover, the commenter argues that some affected States have expressed hesitancy to participate in interstate or even intrastate NOx trading programs.

The EPA continues to believe that industrial cogeneration units can achieve similar NOx emission reductions as utility units. Post-combustion NOx control technologies, like SNCR and SCR, are available to industrial units that cannot achieve NOx reductions using combustion controls. Both SCR and SNCR are proven technologies demonstrated on industrial and utility units, including paper and pulp industry units. See *White Paper - Selective Catalytic Reduction (SCR) for Controlling NOx Emissions*, ICAC, 1997 and *White Paper - Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions*, ICAC, 1997. At the same time, this rulemaking provides for multiple compliance options including trading of allowances. The Agency believes that a significant number of allowances will be available for trading. The Integrated Planning

Model (IPM) analysis shows a significant number of allowances will be available in 2003 when trading begins (see the Regulatory Impact Analysis for further discussion). The compliance supplement pool also provides further allowances in the trading market (see compliance supplement pool discussion in Section III below). In addition, EPA is aware of several States in the process of developing a trading program under the NOx SIP call. Furthermore, a trading program will be promulgated for this section 126 rulemaking.

For all of these reasons, EPA believes that it is appropriate to consider all units that generate electricity for sale as one source category, regardless of whether the owners and operators of the units are traditional utilities, independent power producers, or industrial companies. (Indeed, it may be appropriate at some time in the future to consider all units generating electricity, whether for sale or internal use, as a single category). However, for purposes of this rulemaking, EPA is continuing to apply to existing units the definition of EGU based on firm-contract sales, essentially as clarified in the December 24, 1998 correction notice. This definition does not classify either all existing or new units that generate electricity, or all existing or new units that generate electricity for sale, as EGUs. For example, industrial units that generate electricity only for internal use will be considered non-EGUs. Furthermore, most existing industrial units that sell small amounts of electricity will also not be considered EGUs, because most of these units do not sell electricity under firm contract. Even though EPA is not basing the EGU and non-EGU definitions on the one-third potential capacity/25 MWe threshold supported by the commenters, EPA believes that the definition for existing units classifies the units of the commenter's members in a way that is consistent with the way the commenters have suggested those units should be classified, i.e., as non-EGUs.

The EGU and non-EGU definitions based on any sales of electricity will apply to units that commence operation on or after January 1, 1999. These definitions will not apply to any of the units referenced by the commenter (e.g., the units referenced, but not identified, in the commenter's April 7, 1999 comments for which the commenter provided information on actual, annual electricity sales). Thus, in general, any new units that serve generators involved in electricity sales will be EGUs. The EPA

intends to make parallel clarifications to the definition of EGU under the NOx SIP call rulemaking. The EPA believes that the definition of EGU needs to be consistent across the NOx SIP call, section 126, and FIP rulemakings because it is possible that at one time a source might be subject to control requirements under one of these mechanisms, while at another time a source might be subject to control requirements under another one of these mechanisms. Changing the category that a source has been placed in because of this change in regulatory structure could be confusing and burdensome for the source.

While EPA is not including all sources that generate electricity for sale or internal use as EGUs at this time, EPA may for all of the reasons explained above, consider whether this would be appropriate in future rulemakings.

4. Final Rule EGU/Non-EGU Classification

In summary under today's final rule, EPA will take a three-step approach to determining which of the following categories a boiler or turbine fit into: large EGU, small EGU, large non-EGU, or small non-EGU. First, EPA will determine the date upon which a unit commenced operation. Second, EPA will determine if a boiler or turbine should be classified into the category of EGU or non-EGU by applying the appropriate criteria depending on the date on which the boiler or turbine commenced operation. Finally, EPA will determine if the boiler or turbine should be classified as large or small.

For units that commenced operation before January 1, 1999, EPA will classify as an EGU any boiler or turbine that sells any electricity to the grid under firm contract. For units that commenced operation on or after January 1, 1999, EPA intends, in general, to classify as an EGU any boiler or turbine that produces any amount of electricity for sale.

Once EPA determines that a boiler or turbine should be classified as an EGU, EPA then will classify the unit as a small or large EGU. For a unit that commenced operation before January 1, 1999, EPA will consider the unit a small EGU if it serves a generator less than or equal to 25 MWe and a large EGU if it serves a generator greater than 25 MWe. For a unit that commenced operation on or after January 1, 1999 and sells any electricity, EPA will consider the unit a small EGU if it serves a generator that is less than or equal to 25 MWe and that has the potential to use more than 50 percent of the potential electrical output

capacity of the unit. Units that serve generators greater than 25 MWe and that sell any electricity will be considered large EGUs.

All other boilers and turbines will be considered non-EGUs. This includes boilers and turbines that commence operation on or after January 1, 1999 connected to generators equal to or less than 25 MWe from which any electricity is sold and that have the potential to use 50 percent or less of the potential electrical output capacity of the boiler or turbine. This also includes any unit that commenced operation before January 1, 1999 that did not produce electricity for sale under firm contract.

Non-EGUs will be considered large if their maximum rated heat input capacity is greater than 250 mmbtu/hour and will be considered small if their maximum rated heat input capacity is equal to or less than 250 mmbtu/hour.

The EPA intends to address comments related to inconsistencies between this definition and the applicability requirements of part 97, when EPA promulgates part 97 in July.

J. Cost Effectiveness of Emissions Reductions

As described in Section II.A, above, one part of the significant-contribution interpretation that EPA applied in the NOx SIP call rule, and that EPA applies for purposes of today's final rule, is the extent to which "highly cost-effective" NOx control measures are available for the types of stationary sources named in the petitions[27]. As in the NOx SIP call rule (63 FR at 57399) and the proposed section 126 rule (63 FR at 56304), the EPA has selected these highly cost-effective measures by examining the technological feasibility, administrative feasibility and cost-per-ton-reduced of various multi-state ozone season NOx control measures in light of other actions taken by EPA and States to control NOx.

1. Identifying Highly Cost Effective NOx Controls Levels

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[27]As discussed in this section, the highly cost-effective NOx controls happen to apply only to large stationary sources. Under section 126, EPA can make a finding for "any major source or group of stationary sources." In other words, even if not all sources subject to this action were major, they would be part of a group of stationary sources that contribute significantly to nonattainment and hence could potentially be subject to a finding.

For the reasons set forth in the preamble, part 52 of chapter 1 of title 40 of the Code of Federal Regulations is amended as follows:

PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

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

Authority: 42 U.S.C. 7401-7671q.

Subpart A - General Provisions [amended]

2. Subpart A is amended to add §52.34 to read as follows:

§52.34 Action on petitions submitted under section 126 relating to emissions of nitrogen oxides.

(a) Definitions. For purposes of this section, the following definitions apply:

(1) *Administrator* means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

(2) *Large Electric Generating Units (large EGUs)* means:

(i) For units that commenced operation before January 1, 1997, a unit serving during 1995 or 1996 a generator that had a nameplate capacity greater than 25 MWe and produced electricity for sale under a firm contract to the electric grid.

(ii) For units that commenced operation on or after January 1, 1997 and before January 1, 1999, a unit serving at any time during 1997 or 1998 a generator that had a nameplate capacity greater than 25 MWe and produced electricity for sale under a firm contract to the electric grid.

(iii) For units that commence operation on or after January 1, 1999, a unit serving at any time a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale.

(3) *Large Non-Electric Generating Units (large non-EGUs)* means:

(i) For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input greater than 250 mmBtu/hr and that did not serve during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid.

(ii) For units that commenced operation on or after January 1, 1997 and before January 1, 1999, a unit that has a maximum design heat input greater than 250 mmBtu/hr and that did not serve at any time during 1997 or 1998 a generator producing electricity for sale under a firm contract to the electric grid.

(iii) For units that commence operation on or

after January 1, 1999, a unit with a maximum design heat input greater than 250 mmBtu/hr that:

(A) At no time serves a generator producing electricity for sale; or

(B) At any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 MWe or less and has the potential to use 50 percent or less of the potential electrical output capacity of the unit.

(4) *New sources* means new and modified sources.

(5) *NOx* means oxides of nitrogen.

(6) *NOx allowance* means an authorization by the permitting authority or the Administrator to emit up to one ton of nitrogen oxides during the control period of the specified year or of any year thereafter.

(7) *OTAG* means the Ozone Transport Assessment Group (active 1995-1997), a national work group that addressed the problem of ground-level ozone and the long-range transport of air pollution across the Eastern United States. The OTAG was a partnership between EPA, the Environmental Council of the States, and various industry and environmental groups.

(8) *Ozone season* means the period of time beginning May 1 of a year and ending on September 30 of the same year, inclusive.

(9) *Potential electrical output capacity* means, with regard to a unit, 33 percent of the maximum design heat input of the unit.

(10) *Unit* means a fossil-fuel fired stationary boiler, combustion turbine, or combined cycle system.

(b) Purpose and Applicability. Paragraphs (c) through (h) of this section set forth EPA's affirmative technical determinations, with respect to the national ambient air quality standards (NAAQS) for ozone, that certain new and existing sources of emissions of nitrogen oxides ("NOx") in certain States emit or would emit NOx in amounts that contribute significantly to nonattainment in, or interfere with maintenance by, one or more States that submitted petitions in 1997-1998 addressing such NOx emissions under section 126 of the Clean Air Act. (As used in this section, the term new source includes modified sources, as well.) Paragraph (i) of this section sets forth EPA's decisions about whether to grant or deny each of those petitions, and the remainder of this section sets forth the emissions-reduction requirements that will apply to the affected sources of NOx emissions to the extent any of the petitions are granted.

(1) The States that submitted such petitions are Connecticut, Maine, Massachusetts, New Hampshire, New York, Pennsylvania, Rhode Island, and Vermont (each of

Commonwealth of Pennsylvania
GOVERNOR'S OFFICE

EXECUTIVE ORDER

Subject:			Number:
Regulatory Review and Promulgation			**1996–1**
Date: **February 6, 1996**	Distribution: **B**	By Direction Of: Tom Ridge Thomas J. Ridge, Governor	

WHEREAS, the volume and scope of regulations promulgated by Commonwealth agencies has grown at an alarming rate in recent years; and

WHEREAS, a regulation should be promulgated only after a determination that it is necessary to address a compelling public interest; and

WHEREAS, political subdivisions and the private sector have often been asked to comply with regulations that were drafted and promulgated without meaningful input from these members of the regulated community; and

WHEREAS, burdensome regulations have placed undue restrictions on the regulated community and have hampered Pennsylvania's ability to compete effectively with other states; and

WHEREAS, despite the increasing volume and burden of regulations, they remain an appropriate and necessary means of protecting the public health and safety.

NOW, THEREFORE, I, Thomas J. Ridge, Governor of the Commonwealth of Pennsylvania, by virtue of the authority vested in me by the Constitution of the Commonwealth of Pennsylvania, the Regulatory Review Act, and other laws, do hereby establish the following procedures regarding the review and promulgation of regulations:

1. General Requirements. In the drafting and promulgating of new regulations and the application and review of existing regulations, all agencies shall adhere to the following principles:

a. Regulations shall address a compelling public interest.

b. Costs of regulations shall not outweigh their benefits.

c. Regulations shall be written in clear, concise and, when possible, nontechnical language.

Exhibit F

d. Regulations shall address definable public health, safety, or environmental risks.

e. Where federal regulations exist, Pennsylvania's regulations shall not exceed federal standards unless justified by a compelling and articulable Pennsylvania interest or required by state law.

f. Compliance shall be the goal of all regulations.

g. Where viable nonregulatory alternatives exist, they shall be preferred over regulations.

h. Regulations shall be drafted and promulgated with early and meaningful input from the regulated community.

i. Regulations shall not hamper Pennsylvania's ability to compete effectively with other states.

j. All agency heads shall be held directly accountable for regulations promulgated by their respective agencies.

2. Evaluation of Existing Regulations.

a. Existing regulations shall be reviewed by agencies for consistency with the aforementioned principles. Any regulations that are inconsistent with these principles shall be considered for amendment or repeal.

b. Agency heads shall have the flexibility to construct a program that reviews their existing regulations to assure consistency with these principles. A plan and schedule for review of existing regulations is to be submitted to the Governor's Policy Office within six months of the effective date of this order. All review programs shall commence within one year of the effective date of this order.

c. Regulations proposed for repeal should be submitted to the General Counsel, Secretary of the Budget, and Governor's Policy Director along with a Repeal Analysis Form. The analysis shall state:

- The name of the agency.
- The name of a contact person at that agency.
- A short title of the regulation.
- An explanation of the regulation.
- A justification for the proposed repeal.
- A proposed schedule for repeal – noting any public comment periods.
- Any costs and/or savings associated with the repeal.

d. If a statute prohibits the repeal of a regulation that the agency deems to be inconsistent with the aforementioned principles, the agency head shall submit to the General Counsel, Governor's Policy Director, and Secretary for Legislative Affairs the specific citation for the statute that prohibits the repeal and the citation for any regulation that is determined to be inconsistent with the aforementioned principles, the nature of and reason for the inconsistency, and a recommendation for legislative action, if appropriate.

3. Pre-Drafting and Drafting Guidelines.

a. Before drafting a regulation, agencies, where practical, shall undertake extensive public outreach to those who are likely to be affected by the regulation. Creating advisory committees, using regulatory negotiation, and developing other creative procedures are encouraged as means to solicit the public's input during the regulatory development process.

b. Those to be affected by the regulation should continue to be consulted during the drafting process. When appropriate, members of the regulated community should be involved with the formulation of language, the development of standards, and any other areas in which the regulated community has an interest and/or can provide insight. During the regulation development and drafting process, agencies should advise and consult with the Governor's Policy Office, Office of General Counsel, and the Budget Office whenever the agency determines that any such involvement would hasten the review process.

c. Each agency shall develop its own policies regarding public involvement tailored best to meet the needs of the agency and the regulated community.

d. Within six months of the effective day of this order, agencies shall submit to the Governor's Policy Office their internal guidelines for pre-drafting and drafting public outreach.

4. Review by Governor's Office.

a. Prior to submitting a proposed rulemaking, the agency head shall evaluate each regulation and attest to the fact that the regulation addresses a compelling public need that can be best remedied by the promulgation of the regulation.

b. The agency head shall submit to the General Counsel, Secretary of the Budget, and Governor's Policy Director a written Regulatory Analysis. The analysis shall state:

- The name of the agency.
- The name of a contact person at that agency.
- A short title for the regulation and a citation from the Pennsylvania Code.
- Whether the regulation is a proposed, final-form or final-omitted rulemaking.
- A brief, clear and, if possible, nontechnical explanation of the regulation.
- The statutory authority or mandate for the regulation.
- The compelling public need that justifies the regulation.
- The public health, safety, or environmental risks associated with nonregulation.
- Individuals or groups that are likely to benefit from the regulation.

- Individuals, groups, or entities that will be required to comply with the regulation.
- The outreach conducted by the agency with the regulated community prior to submission of the regulation.
- An estimate of the costs and/or savings associated with compliance and implementation.
- A cost/benefit analysis of the regulation.
- Nonregulatory alternatives considered and the reasons for their dismissal.
- Alternative regulatory schemes considered and the reasons for their dismissal.
- A statement of the compelling Pennsylvania interest if the regulation exceeds federal standards.
- Any requirements that would place Pennsylvania at a competitive disadvantage compared to other states.
- An intra-agency review schedule for the regulation.

c. Each regulation submitted for review shall contain a brief preamble, written in clear and concise language, which shall describe in nontechnical terms the compelling public need the regulation is designed to address, what the regulation requires in legal and practical terms, and who the regulation is likely to affect.

d. The regulatory analysis, along with the preamble and draft regulation, will be reviewed by the Office of General Counsel for form, language, and legal authority. The Governor's Policy Office will review the request to determine that public interest is compelling, that no viable alternative to the regulation exists, and that the costs of the regulation reasonably relate to the benefits. The Office of General Counsel will also consider whether the proposed regulation exceeds federal standards. If the regulation does exceed federal standards, the Policy Office will then evaluate whether the regulation is justified by a compelling and unique Pennsylvania interest. The Budget Office will evaluate the cost analysis prepared by the agency and prepare a fiscal note for the regulation.

e. No agency shall proceed with a proposed, final-form or final-omitted regulation until the General Counsel, Secretary of the Budget, and Policy Director have informed the agency that the regulation is consistent with the regulatory principles and overall policies of the Administration. Review by these three offices will be conducted in a fair and timely manner.

5. Nonregulatory Documents.

a. Nonregulatory public documents such as internal guidelines, policy statements, guidance manuals, decisions, rules and other written materials that provide directives, guidance, or other relevant compliance related information to the public shall be cataloged by every agency.

b. The cataloged titles of these documents, along with an agency contact and phone number, shall be published in the Pennsylvania Bulletin on August 3, 1996. Each year thereafter every agency shall publish and update its list in the Pennsylvania Bulletin on the first Saturday in August.

6. Petitions. To further the goal of greater public participation in the regulatory process; individuals, groups, and businesses are encouraged to use the regulatory petition process outlined in *1 PA Code Section 35.18.* Agencies that have not already done so shall develop internal procedures to receive and review petitions in a fair and timely manner.

7. Continual Review of Regulations. All regulations shall be reviewed in accordance with the review schedule published annually by each agency. As part of its review, the agency shall determine whether the regulation continues to effectively fulfill the goals for which it was intended and remains consistent with the previously-mentioned principles.

8. Regulatory Agendas. Semiannually, on February 1 and July 1, each agency head shall submit to the General Counsel, the Secretary of the Budget, and the Governor's Policy Office Director, for publishing in the *Pennsylvania Bulletin,* an agenda of regulations under development or consideration. The agenda shall describe the regulations being considered, the proposed date for promulgation, the need and legal basis for the action being taken, and the status of regulations previously listed on the agenda. Each item on the agenda shall also include a contact person within the agency from whom additional information may be obtained.

9. Exemptions. The procedure prescribed by this Order shall not apply to:

a. Emergency regulations as defined in the Regulatory Review Act.

b. Any regulation for which consideration or reconsideration under the terms of this order would conflict with deadlines imposed by statute, consent decree or by judicial order, provided that any such regulation shall be reported to the Director of the Governor's Policy Office together with a brief explanation of the conflict. The agency shall publish in the *Pennsylvania Bulletin* a statement of the reasons why it is impracticable for the agency to follow the procedures of this order with respect to such a rule. The agency, in consultation with the Governor's Policy Office, shall adhere to the requirements of this order to the extent permitted by statutory or judicial deadlines.

10. Applicability.

a. This order shall apply to all agencies under the jurisdiction of the Governor's Office.

b. This order is intended only to improve the internal management of executive agencies and is not intended to create any right or benefit, substantive or procedural, enforceable at law by a party against the Commonwealth, its agencies, its officers or any person.

11. Effective Date. This order is effective immediately

12. Rescission. Executive Order 1982-2 is rescinded.

DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR QUALITY DIVISION

AIR POLLUTION CONTROL

Filed with the Secretary of State on
These rules take effect 15 days after filing with the Secretary of State

(By authority conferred on the director of the department of environmental quality by sections 5503 and 5512 of Act No. 451 of the Public Acts of 1994, as amended, and Executive Reorganization Order No. 1995-16, being §§324.5503, 324.5512, and 324.99903 of the Michigan Compiled Laws)

R 336.1801 is added to the Michigan Administrative Code to read as follows:

PART 8. EMISSION LIMITATIONS AND PROHIBITIONS--OXIDES OF NITROGEN

R 336.1801 EMISSION OF OXIDES OF NITROGEN FROM STATIONARY SOURCES.

RULE 801.

(1) ANY OWNER OR OPERATOR OF A FOSSIL-FUEL FIRED ELECTRICITY GENERATING UTILITY UNIT WITH A POTENTIAL TO EMIT OXIDES OF NITROGEN OF MORE THAN 25 TONS PER OZONE SEASON AND SERVING A GENERATOR WITH A NAMEPLATE CAPACITY OF 25 MEGAWATT OR GREATER SHALL COMPLY WITH THE EMISSION LIMITS, DURING THE OZONE SEASON, AS SPECIFIED IN THE FOLLOWING SUBDIVISIONS:

(a) BY APRIL 1, 2002, MEET THE LEAST STRINGENT OF A UTILITY SYSTEM-WIDE AVERAGE OXIDES OF NITROGEN EMISSION RATE OF 0.35 POUNDS PER MILLION BRITISH THERMAL UNITS HEAT INPUT, OR AN EMISSION RATE BASED ON 55 PERCENT REDUCTION OF OXIDES OF NITROGEN FROM 1990 LEVELS.

18 (b) BY APRIL 1, 2004, MEET THE LEAST STRINGENT OF A UTILITY SYSTEM-
19 WIDE AVERAGE OXIDES OF NITROGEN EMISSION RATE OF 0.25 POUNDS PER
20 MILLION BRITISH THERMAL UNITS HEAT INPUT, OR AN EMISSION RATE
21 BASED ON 65 PERCENT REDUCTION OF OXIDES OF NITROGEN FROM 1990
22 LEVELS.
23 (c) THE DATES LISTED IN SUBDIVISIONS (a) AND (b) OF THIS SUBRULE MAY
24 BE EXTENDED BY UP TO 1 YEAR IF AN OWNER OR OPERATOR MAKES AN
25 ACCEPTABLE DEMONSTRATION TO THE DEPARTMENT THAT THE
26 ADDITIONAL TIME IS NECESSARY TO AVOID DISRUPTION OF THE ENERGY
27 SUPPLY IN THE STATE.
28 (2) COMPLIANCE WITH THE EMISSION LIMITS IN SUBRULE (1) OF THIS RULE
29 SHALL BE DETERMINED BY EITHER OF THE FOLLOWING, AS APPROPRIATE:
30 (a) TO DEMONSTRATE COMPLIANCE WITH A UTILITY SYSTEM-WIDE
31 AVERAGE EMISSION RATE, THE SUM OF THE MASS EMISSIONS FROM ALL
32 UNITS OWNED OR OPERATED BY THE UTILITY SUBJECT TO SUBRULE (1) OF
33 THIS RULE, THAT OCCURRED DURING THE OZONE SEASON, DIVIDED BY THE
34 SUM OF THE HEAT INPUT FROM ALL UNITS OWNED OR OPERATED BY THE
35 UTILITY SUBJECT TO SUBRULE (1) OF THIS RULE, THAT OCCURRED DURING
36 THE OZONE SEASON, SHALL BE LESS THAN OR EQUAL TO THE LIMITS IN
37 SUBRULE (1).
38 (b) TO DEMONSTRATE COMPLIANCE WITH THE PERCENT REDUCTION
39 REQUIREMENTS OF SUBRULE (1) OF THIS RULE, THE OWNER OR OPERATOR
40 SHALL PROVIDE CALCULATIONS SHOWING THAT THE UTILITY SYSTEM

41 AVERAGE EMISSION RATE DURING EACH COMPLIANCE OZONE SEASON HAS
42 BEEN REDUCED BELOW THE 1990 OZONE SEASON AVERAGE EMISSION RATE
43 BY THE APPLICABLE PERCENT REDUCTION LISTED IN SUBRULE (1) OF THIS
44 RULE. THE 1990 OZONE SEASON AVERAGE EMISSION RATE IS THE SUM OF
45 THE MASS EMISSIONS FROM ALL UNITS OWNED OR OPERATED BY THE
46 UTILITY SUBJECT TO SUBRULE (1) OF THIS RULE THAT OCCURRED DURING
47 THE 1990 OZONE SEASON, DIVIDED BY THE SUM OF THE HEAT INPUT FROM
48 ALL UNITS OWNED OR OPERATED BY THE UTILITY SUBJECT TO SUBRULE (1)
49 OF THIS RULE THAT OCCURRED DURING THE 1990 OZONE SEASON.
50 (3) BY APRIL 1, 2003, THE OWNER OR OPERATOR OF A FOSSIL-FUEL FIRED
51 EMISSION UNIT WITH A POTENTIAL TO EMIT OF MORE THAN 25 TONS OF
52 OXIDES OF NITROGEN PER OZONE SEASON, EXCEPT EMISSION UNITS SUBJECT
53 TO SUBRULE (1) OF THIS RULE, THAT HAS A MAXIMUM RATED HEAT INPUT
54 CAPACITY GREATER THAN 250 MILLION BRITISH THERMAL UNITS PER HOUR
55 SHALL COMPLY WITH THE FOLLOWING APPLICABLE PROVISIONS, AVERGED
56 OVER THE OZONE SEASON:
57 (a) ANY OWNER OR OPERATOR OF A FOSSIL FUEL-FIRED BOILER OR
58 PROCESS HEATER SHALL MEET THE EMISSION LIMITS CONTAINED IN
59 TABLE 81 OF THIS RULE.
60 (b) ANY OWNER OR OPERATOR OF A GAS-FIRED BOILER OR PROCESS
61 HEATER THAT FIRES GASEOUS FUEL WHICH CONTAINS MORE THAN 50
62 PERCENT HYDROGEN BY VOLUME SHALL COMPLY WITH A OXIDES OF
63 NITROGEN EMISSION LIMIT OF 0.25 POUNDS PER MILLION BTU HEAT INPUT.

ORDER OF THE STATE OF WISCONSIN
NATURAL RESOURCES BOARD
RENUMBERING, AMENDING AND CREATING RULES

The Wisconsin Natural Resources Board proposes an order to renumber NR 484.04(28), to amend NR 428.01(1), 428.02 (intro.), 484.04(13), and to create NR 428.01(2) Note, NR 428.02(1) to (71), NR 428 subchapters I to IX and 484.04(28) to (32) in response to U.S. EPA's nitrogen oxides (NO_x) emission reduction requirements under its NO_x SIP Call to Reduce Ozone Transport.

AM-15-99

Analysis Prepared by the Department of Natural Resources

Authorizing statutes: ss. 227.11(2)(a) and 285.11(1), Stats.

Statutes interpreted: s. 285.11(6), Stats. The State Implementation Plan developed under that provision is revised.

U.S. EPA required states to adopt new regulations in response to its NO_x SIP Call to Reduce Ozone Transport. The SIP call established a nitrogen oxides (NO_x) emissions budget for Wisconsin (and 21 other states) and gave the state some discretion as to how the reductions in NO_x emissions would be achieved. EPA established the emissions budget by assuming the application of "highly cost-effective" controls on large NO_x emission sources. The department identified the sources required to reduce their NO_x emissions and worked extensively with stakeholders (e.g., electric utilities, Wisconsin Paper Council, Wisconsin Manufacturers and Commerce, environmental groups, other state agencies) to develop control programs for these source categories.

The proposed revisions to the state nitrogen oxides emission control program incorporate the provisions of EPA's model NO_x emissions trading rule (40 CFR part 96) as well as additional provisions of 40 CFR Parts 72 and 75 into the Wisconsin Administrative Code. Except for the conversion of the federal text into state numbering and writing style (including terminology), federal formatting is followed pursuant to s. 227.14(1m), Stats., and the proposed provisions of the state nitrogen oxides emission reduction program are identical to the corresponding federal rule language. In this way the state version of the nitrogen oxides emission reduction program is neither more stringent nor less stringent than the federal nitrogen oxides emission reduction program.

The most significant feature of the proposed rule is the effect of subchapter V, NO_x Allowance Allocations. Affected sources are allocated a fixed number of tons of allowable nitrogen oxides emissions (NO_x) for each ozone season (May 1 through September 30), which effectively determines the required level of NO_x emission reduction for each ozone season.

Exhibit H

any fuel.

(69) "Unit operating hour" or "hour of unit operation" means any hour, or fraction of an hour, during which a unit combusts any fuel.

(70) "Utilization" means the heat input (expressed in mmBtu/time) for a unit. The unit's total heat input for the control period in each year will be determined in accordance with 40 CFR part 75 if the NO_x budget unit was otherwise subject to the requirements of 40 CFR part 75 for the year, or will be based on the best available data reported to the administrator for the unit if the unit was not otherwise subject to the requirements of 40 CFR part 75 for the year.

SECTION 5. NR 428 subchs. I to IX are created to read:

NR 428 SUBCHAPTER I

NO_x BUDGET TRADING PROGRAM GENERAL PROVISIONS

NR 428.04 APPLICABILITY; PURPOSE; AND SCOPE. (1) APPLICABILITY. (a) The following units shall be NO_x budget units, and any source that includes one or more NO_x budget units shall be a NO_x budget source, subject to the requirements of this chapter:

1. Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than 25 MWe and sells any amount of electricity; or

2. Any unit that is not a unit under subd. 1. and that has a maximum design heat input greater than 250 mmBtu/hr.

(b) Notwithstanding par. (a), a unit under par. (a) shall be subject only to the requirements of pars. (c) to (e) if the unit has a federally enforceable permit that meets the requirements of par. (c) and restricts the unit to burning only natural gas or fuel oil during a control period in 2003

or later and each control period thereafter and restricts the unit's operating hours during each control period to the number of hours, determined in accordance with par. (c)2. and 3., that limits the unit's potential NO_x mass emissions for the control period to 25 tons or less. Notwithstanding par. (a), starting with the effective date of the federally enforceable permit, the unit may not be treated as a NO_x budget unit.

(c) For each control period under par. (b), the federally enforceable permit must:

1. Restrict the unit to burning only natural gas or fuel oil.

2. Restrict the unit's operating hours to the number calculated by dividing 25 tons of potential NO_x mass emissions by the unit's maximum potential hourly NO_x mass emissions.

3. Require that the unit's potential NO_x mass emissions shall be calculated as follows:

a. Select the default NO_x emission rate in Table 2 of 40 CFR 75.19(c)(1)(ii) that would otherwise be applicable assuming that the unit burns only the type of fuel, i.e., only natural gas or only fuel oil, that has the highest default NO_x emission factor of any type of fuel that the unit is allowed to burn under the fuel use restriction in subd. 1.; and

b. Multiply the default NO_x emission rate under subpar. a. by the unit's maximum rated hourly heat input. The owner or operator of the unit may petition the department to use a lower value for the unit's maximum rated hourly heat input than the value as defined in s. NR 428.02(32). The department may approve a lower value if the owner or operator demonstrates that the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and that the lower value is representative of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

4. Require that the owner or operator of the unit shall retain at the

source that includes the unit, for 5 years, records demonstrating that the operating hours restriction, the fuel use restriction and the other requirements of the permit related to these restrictions were met.

5. Require that the owner or operator of the unit shall report the unit's hours of operation, treating any partial hour of operation as a whole hour of operation, during each control period to the department by November 1 of each year for which the unit is subject to the federally enforceable permit.

(d) The department, in issuing a federally enforceable permit with the fuel use restriction under par. (c)1. and the operating hours restriction under par. (c)2. and 3., shall notify the administrator in writing of each unit under par. (a) whose federally enforceable permit issued by the department includes these restrictions. The department shall also notify the administrator in writing of each unit under par. (a) whose federally enforceable permit issued by the department is revised to remove any of these restrictions, whose federally enforceable permit issued by the department includes any of these restrictions that is no longer applicable, or which does not comply with any of these restrictions.

(e) If, for any control period under par. (b), the fuel use restriction under par. (c)1. or the operating hours restriction under par. (c)2. and 3. is removed from the unit's federally enforceable permit or otherwise becomes no longer applicable or if, for any control period, the unit does not comply with the fuel use restriction under par. (c)1. or the operating hours restriction under par. (c)2. and 3., the unit shall be a NO_x budget unit, subject to the requirements of this chapter. The unit shall be treated as commencing operation and, for a unit under par. (a)1., commencing commercial operation on September 30 of the control period for which the fuel use restriction or the operating hours restriction is no longer applicable or during which the unit does not comply with the fuel use restriction or the operating hours

restriction.

(2) PURPOSE. This subchapter establishes general provisions and the applicability provisions for the NO_x budget trading program for the state of Wisconsin as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor. The department authorizes the administrator to assist the department in implementing the NO_x budget trading program by carrying out the functions set forth for the administrator in this chapter.

(3) SCOPE. The regulations under this chapter set forth certain generally applicable provisions under the NO_x budget trading program. The regulations also set forth requirements for obtaining and revising the NO_x budget portion of an operation permit issued by the department. The requirements under this chapter supplement, and in some cases modify, the requirements under chs. NR 406 and 407 as these requirements apply to sources subject to the NO_x budget program.

NR 428.05 RETIRED UNIT EXEMPTION. (1) APPLICABILITY. This section applies to any NO_x budget unit, other than a NO_x budget opt-in source, that is permanently retired.

(2) SCOPE OF EXEMPTION. (a) Any NO_x budget unit, other than a NO_x budget opt-in source, that is permanently retired shall be exempt from the NO_x budget trading program of this chapter, except for the provisions of this section, ss. NR 428.02, 428.04 and 428.07, and subchs. V, VI and VII.

(b) The exemption under par. (a) shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NO_x authorized account representative, authorized in accordance with subch. II, shall submit a statement to the department. A copy of the statement shall be submitted to the administrator. The statement shall state, in a format prescribed by the department, that the unit is permanently retired and will comply with the requirements of sub. (3).

(c) After receipt of the notice under par. (b), the department shall amend any permit covering the source at which the unit is located to add the provisions and requirements of the exemption under par. (a) and sub. (3).

DRAFT

10 CSR 10-6.350 Emissions Trading of NOx

PURPOSE: The purpose of this rule is to establish an emissions trading program for the state of Missouri for emissions of nitrogen oxides (NOx). This rule will require large stationary sources of NOx emissions to meet a seasonal NOx cap. The procedures for distribution of NOx allowances for all affected sources will be established through this rule. The reductions in NOx emissions will reduce the transport of ozone and its precursors within the state of Missouri and to other states as required under the Clean Air Act.

(1) Applicability.
- (A) This rule applies to any fossil fuel-fired electric generating unit (EGU) that serves a generator with a nameplate capacity of greater than 25 megawatts (MW).
- (B) This rule applies to any fossil fuel-fired non-EGU -
  1. with a maximum rated heat input greater than 250 million British thermal units per hour (mmBtu/hr), or
  2. had emissions of oxides of nitrogen (NOx) of 100 tons per control period or greater during the control period in 1995, 1996 or 1997.
- (C) This rule applies to any facility that opts-in to the NOx budget trading program by obtaining a NOx budget source opt-in permit from the permitting authority.
- (D) Exemptions. Any unit under subsections (1)(A) and (1)(B) of this rule with a federally enforceable operating permit that limits the unit's mass NOx emissions to twenty-five (25) tons or less during the control period is exempt from the requirements of this rule.

(2) Definitions
- (A) Definitions of certain terms in this rule, other than those specified in this rule section, may be found in 10 CSR 10-6.020.
- (B) Account certificate of representation - the completed and signed submission for certifying the designation of a NOx authorized account representative for a NOx budget source or a group of identified NOx budget sources who is authorized to represent the owners and operators of such source or sources and of the NOx budget units at such source or sources with regard to matters under the NOx budget trading program.
- (C) Account number - the identification number given to each NOx budget trading program account.
- (D) Administrator – the administrator of the United States Environmental Protection Agency or the administrator's duly authorized representative.
- (E) Allocate or allocation - the determination by the permitting authority of the number of NOx allowances to be credited to a NOx budget unit or a growth set-aside.
- (F) Allocation period - the period of years or specific years for which the permitting authority will issue NOx allowances.
- (G) Allowance - one ton of NOx emissions during the control period.
- (H) Automated data acquisition and handling system - that component of the CEMS, or other emissions monitoring system approved for use under 40 CFR Part 96 Subpart H, designed to interpret and convert individual output signals from

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May 7, 1999

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400 Market Street
Harrisburg, PA 17101-2301

Re: Proposed Interstate Ozone Transport Reduction Regulations
Written Comments of International Paper Company

Dear Board Members:

International Paper Company is submitting these comments on the proposed Interstate Ozone Transport Reduction Regulations ("OTR Regulations"). These OTR Regulations are required to be implemented by Pennsylvania as a result of EPA's SIP Call.

International Paper has a pulp and paper mill in Erie, Pennsylvania which is significantly impacted by Pennsylvania's proposed OTR Regulations. International Paper's Erie facility is comprised of pulp, paper making and converting operations and employs approximately 900 people. It is one of the largest industrial employers in Erie County, Pennsylvania. The Erie Mill has several sources which would be significantly affected by the OTR Regulation as it is presently drafted.

I. THE DEPARTMENT SHOULD ADOPT EPA's 25 MW CUTOFF AND SELLS ELECTRICITY REQUIREMENT FOR ELECTRIC-GENERATING UNITS

The first issue addressed by these comments responds to the Environmental Quality Board's ("the Board") request for comments on whether OTR Regulation Section 145.4(1) should include electric-generating units of 15 MW or greater despite the fact that EPA is requiring only that electric-generating units of 25 MW capacity or greater be included.

A. The 15 MW Cutoff In The Proposed OTR Regulations Is Broader In Scope Than The 15 MW Cutoff In The NO_x Allowance Regulations.

As an initial matter, in its request for comments, the Board appears to imply that the 15 MW "cutoff" in the OTR Regulation is the same "cutoff established by the NO_x Allowance Requirements" (29 Pa. Bull. 1321, 1322); however, this implication is not supported by the language used in the OTR Regulation. The NO_x Allowance Regulation applies to "all fossil fuel-fired electric-generating sources rated at 15 megawatts or greater." 25 Pa. Code § 121.1 (definition of NO_x Affected Source). In contrast, the OTR Regulation applies to "A unit that, ..., serves a generator with a nameplate capacity greater than or equal to 15 MW." (Emphasis added) (Proposed 25 Pa. Code § 145.4(1).) The use of the term "serves" in the OTR Regulation significantly expands the scope of the OTR Regulation beyond the scope of the NO_x Allowance Regulations. For instance, the NO_x Allowance Regulations apply only to fossil fuel-fired units which generate 15 MW of electricity; however, the proposed OTR Regulation would apply to any fossil fuel-fired unit connected to a 15 MW generator, regardless of how much power that individual unit actually can generate. This expanded definition has significant impacts on the Erie Mill, and goes well beyond existing NO_x Allowance Regulations and what is required or justified by EPA's SIP Call.

B. The Department Has No Basis To Regulate Units That Serve Generators Smaller Than 25 MW.

On October 27, 1998, EPA promulgated as a final rule the "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport Ozone ("the EPA SIP Call"). 63 F.R. 57355. The EPA SIP Call affects 22 states and the District of Columbia. Under the SIP Call, EPA established a NO_x emissions budget for each state by assuming NO_x emission reductions for certain sources. The purpose of the EPA SIP Call is to reduce NO_x emissions that significantly contribute to the nonattainment of the National Ambient Air Quality Standards ("NAAQS") for ozone or that will interfere in the maintenance of such standards. (63 F.R. 57356 (Summary), attached hereto as Exhibit A).

Under its SIP Call, EPA proposes to regulate units that serve 25 MW generators and that sell electricity. EPA, in developing its Model Rule, determined that 25 MW was the appropriate size cutoff for

these units. EPA based this determination on a number of factors. First, EPA determined that emissions from sources below 25 MW are not significant as compared to sources above 25 MW. (63 F.R. 57415, Ex. A; Responses to Significant Comments, D.N. A-97-43, V1-C-01, April 1999, p. 104, attached hereto as Exhibit B). Second, EPA determined that the 25 MW level was consistent size-wise with a 250 MMBtu/hr unit, which is a type of source also covered by the SIP Call. (63 F.R. 25923, attached hereto as Exhibit C; 63 F.R. 57415, Ex. A; Ex. B at p. 104). Third, EPA wanted to maintain consistency between the NO_x Budget Trading Program and the Title IV monitoring requirements which already use a 25 MW cutoff level. (63 F.R. 57461, Ex. C). This consistency reduces the economic impact of EPA's SIP Call because units covered by the Title IV monitoring requirements already are equipped with the costly monitoring equipment which is required under the SIP Call. (63 F.R. 25923, Ex. C). Fourth, the financial impact on a per ton reduction basis is significant on sources below 25 MW as compared to larger sources.[1] (63 F.R. 57378, Ex. A; Ex. B at pp. 121, 165-66). Lastly, EPA determined that including units of less than 25 MW creates significant administrative burdens on the owner/operator of the unit as well as the regulatory agency. (63 F.R. 57415, Ex. A; Ex. B at p. 104).

In deciding not to control sources below 25 MW, EPA has determined that only highly cost-effective NO_x reductions are necessary at this time (i.e., those at $2,000/ton or less) and that controlling sources below 25 MW will not be highly cost-effective. (63 F.R. 57378, Ex. A). More importantly, EPA has specifically determined that emissions from sources below 25 MW do not significantly contribute to ozone NAAQS nonattainment, or interfere with ozone NAAQS maintenance by a downwind state. (63 F.R. 57358, Ex. A; Ex. B at pp. 104, 165). Thus, EPA's analysis only justifies controlling sources that are 25 MW or larger.

It is believed that the Department has conducted no independent analysis which justifies imposing a stricter standard than is required by EPA in its SIP Call. In its Regulatory Analysis Form, the Department relies solely on data contained in EPA's SIP Call.

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[1] For example, unlike the larger sources, most smaller sources do not have the required Continuous Emissions Monitors ("CEMS"), which can cost several hundred thousand dollars per unit. In the Erie Mill's case, under the language proposed by the Department, it would need to install CEMS on three additional units solely because they serve one generator which exceeds 15 MW.

Furthermore, the Department intends to rely solely on EPA's data to demonstrate that the OTR Regulation meets Pennsylvania's SIP Call requirements. As discussed above, EPA's data and analysis only support a cutoff of 25 MW; it does not provide any support for a 15 MW cutoff. Under EPA's analysis, a 15 MW cutoff is not needed to meet Pennsylvania's budget. Thus, there is no rational basis for using a 15 MW cutoff and such a determination is arbitrary and capricious.[2]

C. The Department's OTR Regulation Fails To Include The "Sells Electricity" Requirements Relied Upon By EPA In Determining Pennsylvania's Budget.

The Department's applicability requirement proposed in Section 145.4(1) also fails to include a critical component to EPA's definition. The EPA's applicability requirement not only requires that units serve generators with a capacity equal to or greater than 25 MW, but also that they sell electricity.

As described in EPA's Clarification of EGU Classification for Purposes of Estimating Budget Reductions (63 F.R. 71120-71125, attached hereto as Exhibit D), to determine whether a boiler or turbine constituted an electric-generating unit ("EGU"), EPA examined whether the generator's purpose was to generate electricity for sale. (63 F.R. 71223, Ex. D). In making this determination, EPA relied upon the North American Electric Reliability Council's list of sources which sell power under contract to the electric grid. Id. Sources that are on this list have entered into specific contracts with utilities to sell power when the utilities require it. In the vernacular of the electric generation market, this is known as a sale of capacity. The

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[2] In the EPA's Response to Significant Comments on the Proposed Findings of Significant Contribution and Rulemaking on Section 126 Petitions for Purposes of Reducing Interstate Ozone Transport, EPA rejected comments raised by several commentors, including the Department, that the cutoff should be 15 MW, not 25 MW. (Ex. B at pp. 103-104). EPA stated, "EPA found that the collective emissions from small sources were relatively small ... and the administrative burden, to the permitting authority and to regulated entities, of controlling such sources was likely to be considerable." (Id. at p. 104). Further, "EPA concludes that small sources do not emit in amounts that significantly contribute to petitioning states' nonattainment or maintenance problems." (Id.).

utilities rely upon this capacity availability to satisfy regulatory requirements imposed upon them regarding the amount of electric generation they must have available to meet demands. During the ozone season when electricity demand is usually greatest, utilities use these capacity sources to meet peak electricity demands. Thus, the need to regulate NO_x emissions from such sources is clearly evident.

In contrast, there also are sales of electricity known as the sale of energy. Energy sales are not, and cannot be, relied upon by utilities to satisfy their capacity requirements, nor can a utility require such sales. Typically, sales of energy only occur when an industrial user which generates its own electricity happens to generate more electricity than it can consume at a given time. In Pennsylvania, sales of only energy are governed by regulation, not negotiated contracts. Sales of energy are not the kind of electricity sales intended to be covered by EPA's SIP Call. It is this type of "sale" that the Erie Mill incurs. Ironically, the Erie Mill typically experiences these sales outside of the ozone season when its steam demands are highest due to winter heating requirements.

In its recent Findings of Significant Contribution and Rulemaking in Section 126 Petitions for Purpose of Reducing Interstate Ozone Transport (Dated May 3, 1999) ("126 Petition Rulemaking"), EPA has further clarified what sources it has classified as EGUs and non-EGUs. In this final 126 Petition Rulemaking, EPA adopts the following applicability standards for EGUs and non-EGUs:

1. Large Electric Generating Units (Large EGUs) means:

    a. For units that commenced operation before January 1, 1997, a unit serving during 1995 or 1996 a generator that had a nameplate capacity greater than 25 MWe and produced electricity for sale under a firm contract to the electric grid;

    b. For units that commenced operation on or after January 1, 1997 and before January 1, 1999, a unit serving at any time during 1997 or 1998 a generator that had a nameplate capacity greater than 25 MWe and produced electricity for sale under a firm contract to the electric grid;

c. For units that commence operation on or after January 1, 1999, a unit serving at any time a generator that has a nameplate capacity greater than 25 MWe and produces electricity for sale;

2. Large Non-Electric Generating Units (Large Non-EGUs) means:

a. For units that commenced operation before January 1, 1997, a unit that has a maximum design heat input greater than 250 MMBtu/hr and that did not serve during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid;

b. For units that commenced operation on or after January 1, 1997 and before January 1, 1999, a unit that has a maximum design heat input greater than 250 MMBtu/hr and that did not serve at any time during 1997 and 1998 a generator producing electricity for sale under a firm contract to the electric grid;

c. For units that commence operation on or after January 1, 1999, a unit with a maximum design heat input greater than 250 MMBtu/hr that:

(1) At no time serves a generator producing electricity for sale; or

(2) At any time serves a generator producing electricity for sale, if any such generator has a nameplate capacity of 25 MWe or less and has the potential to use 50 percent or less of the potential electrical output capacity of the unit.

40 C.F.R. § 52.34(a)(2),(a)(3), attached hereto as Exhibit E at pp. 210-211).

EPA also has indicated that it intends to "make parallel clarifications to the definition of EGU under the NO_x SIP Call Rulemaking." ___ F.R. ___, Ex. E at p. 148). The purpose of the changes is to clarify what existing sources EPA identified in the

budget as EGUs and non-EGUs and, for sources commencing operation in the future, to ensure that the forthcoming changes to the electric generation industry does not result in small generators being added into large boilers simply to sell electricity. ___ F.R. ___, Ex. E at pp. 139-140).

Based upon this recently promulgated 126 Petition Rulemaking, EPA clearly intended to control only existing generators that sell capacity to the electric grid, not generators which sold energy only. Thus, EPA defines an EGU as a unit (owned by either a utility, an Independent Power Producer ("IPP") or an industrial user) that provides "capacity" to the electric grid (i.e., electrical power that a utility can rely upon in meeting its obligations under law to have sufficient electrical-generating capacity to meet demands), as opposed to a unit which mostly provides energy for internal use, but which may occasionally incur a sale of "energy" to a utility.

The Department's decision to exclude the electricity sale requirement of the EPA SIP Call fails to recognize an important aspect of EPA's Regulation. EPA's "sells electricity" requirement ensures that sources rated less than 250 MMBtu/hr which serve electric generators that are not utility based are not regulated under this part of the SIP Call. For the same reasons discussed above, the benefit of controlling such sources is outweighed by the significant costs associated with such control. Despite EPA's clear explanation of what sources it has identified as EGUs, the Department has excluded the "sells electricity" requirement from its Regulation and has accordingly expanded the scope of the OTR Regulation to include all 15 MW units which generate electricity, rather than just those which sell electricity for capacity.

D. The Department's Decision To Regulate 15 MW Generators Regardless Of Whether They Sell Electricity Contravenes The Pennsylvania Air Pollution Control Act, The Governor's Executive Order 1996-1 And The Regulatory Review Act.

There is no evidence or analysis which supports a conclusion that units that serve 15 MW generators significantly contribute to nonattainment of the ozone NAAQS or will interfere with maintenance of the ozone NAAQS in downwind states and, therefore, that such units should be regulated under EPA's SIP Call. The regulation of units that serve generators smaller than 25 MW and units which do

not sell capacity to the electric grid is contrary and goes beyond the scope of permissible actions authorized under 35 P.S. § 4004.2, as well as the Board's authority under 35 P.S. § 4005. Furthermore, such regulation bears no rational basis to the purposes of the Act, or the EPA SIP Call. As such, the OTR Regulation will be void and unenforceable.

The Department's decision to expand the scope of the OTR Regulations beyond EPA's SIP Call requirements also violates Executive Order 1996-1 issued February 6, 1996 by Governor Thomas J. Ridge which prohibits Pennsylvania regulations from exceeding federal standards in a manner not justified by a compelling and articulable Pennsylvania interest or required by state law, and which also prohibits regulations which hamper Pennsylvania's ability to compete effectively with other states. (See Executive Order 1996-1, attached hereto as Exhibit F).

The Department has offered no compelling or articulable Pennsylvania interest or state law which justifies exceeding the standards required by the EPA SIP Call. Although the Ozone Transport Commission concluded in 1996 that controlling 15 MW generating units was necessary to reduce ozone transport, EPA, after substantial additional modeling and analysis, has concluded that controlling 25 MW generating units is the most cost-effective way to reduce ozone transport, and that imposing the cost of control on smaller units simply is not supported by the evidence at this time. (Ex. B at p. 121). We can discern no compelling or articulable Pennsylvania interest or state law which contradicts EPA's more educated decision. Further, the Department has offered no evidence which justifies going beyond the EPA applicability standard. In fact, EPA has determined that by solely controlling the sources it has identified, ozone transport will not cause downwind states to violate National Ambient Air Quality Standards for Ozone. Thus, there is no legal or technical basis to control beyond those sources.

International Paper also is greatly concerned that Pennsylvania's proposed Regulation will place Pennsylvania at a significant disadvantage in competing effectively with other states in attracting new business and, more importantly, in retaining existing businesses in Pennsylvania. Pennsylvania is in the unenviable position of having several neighboring states which are subject to the EPA SIP Call, but which were not subject to the NO_x Allowance Regulation. Many of these neighboring states, including Ohio and West Virginia, have challenged EPA's SIP Call as unnecessary. It can be safely presumed that these states will not implement regulations more strict than EPA has promulgated. In

fact, Michigan, which also has challenged the SIP Call, has proposed its SIP Call Regulations which appear even more lenient than EPA's 25 MW applicability standard.[3] Furthermore, any state which fails to submit a SIP will become subject to the Federal Implementation Plan ("FIP") proposed on October 21, 1998, which incorporates the SIP Call Model Rule and its 25 MW, sells electricity applicability requirements.[4] Thus, Pennsylvania clearly will be at a competitive disadvantage to Michigan and most likely will be at a competitive disadvantage to every other non-OTC state which must implement the SIP Call, including states such as Ohio, West Virginia, Wisconsin and Virginia.

It also is likely that Pennsylvania will be at a competitive disadvantage to even other OTC states if it adopts the applicability language presently proposed. For instance, in July of 1998, New Jersey adopted NO_x control regulations in anticipation of EPA's SIP Call. New Jersey's Regulations apply only to 15 MW generating units, not to units that serve 15 MW generators. Thus, Pennsylvania is proposing regulations that would be more strict than New Jersey. It is difficult to imagine that other OTC states would follow Pennsylvania's lead and require stricter regulations than their sister western and southern states. Of all of the proposed Regulations, Pennsylvania would be the only state that would regulate the Erie Mill's small boilers. Thus, Pennsylvania risks having the most stringent NO_x regulations in the nation under its current proposal. This clearly will put Pennsylvania and the Erie Mill at a competitive disadvantage. The proposed Regulation will discourage businesses from coming to Pennsylvania and encourage businesses already located in Pennsylvania to leave.

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3 Michigan's proposed regulations, Rule 810(1), apply to "fossil fuel-fired electric-generating utility unit with a potential to emit oxides of nitrogen of more than 25 tons per ozone season and serving a generator with a nameplate capacity of 25 megawatt or greater...." (Exhibit G). Thus, Michigan's proposed rule clearly covers only utility-based units and only those which serve 25 MW generators. In addition, Michigan is only seeking emission reductions ultimately to .25 lbs/MMBtu, as opposed to EPA's (and Pennsylvania's) .15 lbs/MMBtu requirement. (Id.). Likewise, Wisconsin and Missouri are proposing the 25 MW cutoff and the sells electricity requirement. (See Exhibits H and I).

4 Based on conversations with various states' representatives, it appears at this time that West Virginia, Virginia, South Carolina, Georgia, North Carolina and Alabama will become governed by the FIP and, therefore, will have the 25 MW and sells electricity requirements.

Furthermore, contrary to the requirements of Section 5 of the Regulatory Review Act, the Department failed to estimate the direct and indirect costs of the Regulation upon industrial units. In both the preamble to the OTR Regulations and the Department's response to Section 17 of the Regulatory Analysis Form, the Department considers only the impact on EGU sources, cement plants and internal combustion engines. The Department does not consider the impact on sources outside of the EPA's EGU budget such as "units that serve 15 MW generators," including those with a rated design capacity of less than 250 MMBtu/hr or units with a rated design capacity of 250 MMBtu/hr or greater. The Department also failed to consider the monitoring costs on units, such as those which serve 15 MW generators, that are not subject to the existing NO_x Allowance Regulations or EPA's acid rain program. As described below, the estimated cost of compliance for the sources at the Erie Mill are significantly higher than the $2,000 per ton level adopted by EPA, and there is no evidence that control of these sources is needed in order to attain and maintain the Ozone NAAQS.

E. The Cost To The Erie Mill To Comply With The Proposed Pennsylvania OTR Regulation Far Exceeds The $2,000 Per Ton Of Ozone Season NO_x Reductions Identified By EPA As Highly Cost Effective.

Presently, the Erie Mill has only one boiler subject to the NO_x Allowance Regulation due to its maximum design heat input exceeding 250 MM Btu/hr; however, under the proposed OTR Regulations, three (3) additional boilers will be subject to the OTR Regulation due to the fact that each will "serve a 15 MW generator" through a common steam header.[5] The cost per ozone season ton reduction for these three separate units is staggering, and far exceeds the $2,000 per ozone season ton reduction used by EPA in determining whether a control would be highly cost-effective. Depending upon how the Erie Mill may decide to achieve compliance, the Erie Mill estimates that its cost of control per ton of NO_x reduced in the ozone season (based on actual usage as opposed to maximum usage - EPA's methodology), will be approximately $8,500 (using SNCR plus buying allowances to bridge the gap between .15 lb/MMBtu and the SNCR control level) to $21,700 (using SCR) per ton. Even if it is assumed that NO_x reductions are based on maximum output (which is not how EPA calculated emission reductions), the cost ranges from

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5 All of the boilers have a maximum design heat input of less than 250 MMBtu/hr and none individually can generate 15 MW.

$6,300 (SNCR plus allowances) to $12,600 (SCR) per ton. These costs will severely impede the Erie Mill's ability to operate competitively, especially against similar paper mills located in non-OTC states and in states not covered by the EPA SIP Call.

The Erie Mill does not anticipate that the availability of allowances will help its predicament. As the Department may recall, during the Hearing for the NO_x Allowance Program, the Erie Mill predicted that NO_x Allowances would cost between $5,000 - $10,000 per ton despite the claim that it would only cost utilities $500 per ton to control. Presently, NO_x Allowances are trading in excess of $5,000 per ton. Given that the monitoring system costs alone for each possibly affected unit at the Erie Mill would exceed $2,000 per ozone season ton reduction, the total cost of relying solely on allowances exceeds $7,000 per ton. Clearly, these are the exact kinds of costs, together with the lack of benefits, which led to EPA's decision to exclude units such as those at the Erie Mill from inclusion in the program. Given EPA's expressed uncertainty of the exact impact of ozone transport and the most effective ways to assure downwind attainment, the imposition of such costs cannot be justified.

F. International Paper Recommends That Pennsylvania Adopt The Language Used By EPA In Its Final 126 Petition Rulemaking.

International Paper appreciates the dilemma that Pennsylvania and the other OTC states are in because EPA's SIP Call established 25 MW as the cutoff, whereas the OTC Model Rule adopted a 15 MW cutoff. However, given the significant additional modeling and analysis performed by EPA to support its SIP Call, Pennsylvania must be aware that such modeling and analysis severely undercuts the OTC's decision to use a 15 MW cutoff, especially at the higher reduction requirements of the EPA SIP Call. It also is important to note that the Department's draft goes even further than the NO_x Allowance Regulation which applies only to 15 MW units. Accordingly, International Paper recommends that the Department adopt the applicability cutoffs recommended by EPA in the Final 126 Petition Rulemaking quoted above, which eventually will be incorporated into EPA's SIP Call Model Rule. Alternatively, International Paper recommends the following language for Section 145.4(1):

> A unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than or equal to 25 MW, and which produced electricity for sale under a firm contract to the electric grid.

This language satisfies EPA's 25 MW cut-off requirement, and it further clarifies the sells electricity requirement in a manner consistent with EPA's intent.

II. THE DEPARTMENT SHOULD INCLUDE EPA's EXEMPTION FOR UNITS WILLING TO ACCEPT A 25-TON OZONE SEASON EMISSION LIMIT

International Paper also recommends that the Department adopt the exemption contained in Section 96.4(b) of the Model Rule. (63 F.R. 57518-57519, Ex. A). EPA proposed that units which have a federally-enforceable permit that restricts ozone season emissions to less than 25 tons be exempted from the Regulations. (Id.). EPA proposed this exemption to give units which exceed the applicability thresholds, but which have a low ozone season potential to emit, the alternative of accepting permit restrictions. (63 F.R. 57463, Ex. A). International Paper believes that Pennsylvania needs to adopt this exemption to ensure that its OTR Regulations are not more stringent than is required by EPA's SIP Call.

III. THE DEPARTMENT SHOULD ADOPT EPA's DEADLINE FOR SUBMISSION OF NO_x BUDGET PERMITS

International Paper objects to the requirements of Section 145.21(b)(1) that applications for NO_x Budget Units be submitted within six months of the effective date of the OTR Regulations. First, the OTR Regulations do not become effective until 2003, and even EPA is recommending a permit submission deadline of November, 2001. (See 40 C.F.R. § 96.21(b), 63 F.R. 57522-57523, Ex. A). Pennsylvania's requirements will be nearly two years ahead of EPA's schedule. International Paper believes this time could be better spent by the affected facilities determining applicability and how to come into compliance rather than submitting permit applications that will be either incomplete or ultimately significantly modified or supplemented.

Second, the proposed Pennsylvania OTR Regulations are very vague on what would be required to be submitted with the permit application, and no formal permit application has been developed. Thus, it may not be known within six months of the effective date of these OTR Regulations what the Department exactly will require, which will further limit the time affected facilities have to compile such information. Thus, due to uncontrollable factors, a six-month time frame ultimately may prove to be infeasible; yet it will be part of Pennsylvania's approved SIP and the Department's ability to waive or modify the time frame could be limited. Pennsylvania should give itself more time to implement the permitting strategies.

Third, requiring permit applications over four years in advance of when the permit is needed may result in a great deal of wasted effort as some units for which permit applications are required may not be operating after 2003. Using a permit application date closer in time to the date the permit is needed will reduce that wasted effort. For the above reasons, International Paper recommends that Pennsylvania adopt EPA's recommended application due date of 18 months before May 1, 2003.

IV. THE DEPARTMENT SHOULD APPLY THE MONITORING REQUIREMENTS OF THE OTR REGULATIONS IN A MANNER CONSISTENT WITH THE NO_x ALLOWANCE REGULATIONS

The NO_x Allowance Regulations that have been recently implemented by the Department impose significant new monitoring requirements on the units covered by those Regulations. Companies have spent substantial sums of money to come into compliance with those requirements. International Paper recommends that the Department apply the new Part 75 Subpart H in a manner that is consistent with the monitoring requirements of the NO_x Allowance Regulations.

International Paper also objects to the Department's failure to impose a time limit on itself for reviewing certification applications. Under EPA's proposed Model Rule, Section 96.71(b)(3)(iv) provides that the permitting authority will approve or disapprove a party's certification application within 120 days of receiving a complete application. (63 F.R. 57531-57533, Ex. A). Section 96.71(b)(3)(iv) further provides that if the permitting authority takes no action, the certification application will be deemed approved. (Id.). Section 96.71(b)(3)(iv)(A) provides that the permitting agency will issue a written notice of approval of the certification application within 120 days of receipt of a complete application which shows that the monitoring system meets

the applicable Part 75 requirements. (Id.). EPA's Model Rule further provides that data collected by the monitoring system prior to final certification is considered as valid quality assured data, unless the permitting authority issues the notice of disapproval within 120 days. (Id.). Thus, under EPA's Model Rule, parties are protected from violations if the permitting authority takes too long to review the certification application and ultimately disapproves the certification many months after the application was filed.

The Department's proposed OTR Regulations do not include any provisions requiring the Department to act upon certification application within a specified time period and, accordingly, does not offer parties any protection from violations that may result from a certification application ultimately being denied. Under Section 147.71(b)(V) of the Department's proposed OTR Regulations, units that have their certification application disapproved are required to use the maximum default values provided in 40 C.F.R. Part 75 to determine their emissions. This will almost certainly result in violation of the standards, or consumption of excessive allowances. When this occurs within the normal time frame for application review, such a result seems fair and reasonable; however, when there is no limitation upon how long the Department may take to review an application, such a result is patently unreasonable. Given the limited number of sources affected by the OTR Regulations, the Department should be able to process the certification application within 120 days -- EPA certainly thinks the states can do so. International Paper recommends that the Department incorporate the 120-day permit approval requirement into its OTR Regulations.

V. CONCLUSION

International Paper reiterates the importance to the Erie Mill of the Department modifying its proposed OTR Regulations in a manner consistent with EPA; that is, adopting a 25 MW cutoff and using the requirement that the unit produce electricity for sale under a firm contract to the electric grid.

The costs of the proposed OTR Regulations to the Erie Mill are staggering. Under the currently proposed OTR Regulations, the Erie Mill will have to install separate Part 75 monitoring systems on three boilers, none of which has a rated design capacity that exceeds 250 MMBtu/hr, none of which alone can even generate 15 MW of power, and none of which are regulated by the existing NO_x Allowance Regulations. In addition, the Erie Mill will have to

either control or buy allowances for these three units. It will cost the Erie Mill millions of dollars and place it at a significant competitive disadvantage to paper mills in other states; yet, there will be no benefit to the purpose of the OTR Regulations (and EPA SIP Call) -- no emissions from a significant contributor to ozone nonattainment or interference with the maintenance of ozone attainment will be reduced.

International Paper appreciates the opportunity to comment on the proposed OTR Regulations. If the Department has any questions or wishes to discuss these comments further, please contact me at 814-870-7607.

Very truly yours,

MacDONALD, ILLIG, JONES & BRITTON LLP

By _____
Mark J. Shaw

MJS/tmb/490426
cc: International Paper Company

INTERNATIONAL PAPER COMPANY
SUMMARY OF WRITTEN COMMENTS
OTR REGULATIONS

1. The Department should adopt EPA's 25 MW cutoff and sells electricity requirement for Electric-Generating Units (EGUs).

   a. The 15 MW cutoff in the proposed OTR Regulations is much broader in scope than the 15 MW cutoff in the NO_x Allowance Regulations and goes well beyond what is required or justified by EPA's SIP Call.

   b. The Department has no technical basis to regulate units that serve generators smaller than 25 MW.

   c. The Department has no technical basis to regulate non-EGUs as EGUs by failing to include the "sells electricity" requirement relied upon by EPA in determining Pennsylvania's budget.

   d. Due to stricter applicability standards adopted by the Department in the OTR Regulations, the Erie Mill will have three additional boilers regulated, none of which has a rated design capacity that exceeds 250 MMBtu/hr, none of which alone can even generate 15 MW of power, and none of which are regulated by the existing NO_x Allowance Regulations.

   e. The cost to the Erie Mill to comply with the proposed 15 MW cutoff in the Pennsylvania OTR Regulations far exceeds the $2,000 per ton of ozone season NO_x reductions identified by EPA as highly cost effective.

   f. The Department's adoption of stricter applicability standards contravenes the Pennsylvania Air Pollution Control Act, the Governor's Executive Order 1996-1 and the Regulatory Review Act.

   g. International Paper recommends that Pennsylvania adopt the language used by EPA in its Final 126 Petition Rulemaking.

   h. Alternatively, International Paper recommends the following language:

      > A unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than or equal to 25 MW, and which produces electricity for sale under a firm contract to the electric grid.

2. The Department should include EPA's exemption for units willing to accept a 25-ton ozone season emission limit.

3. The Department should adopt EPA's deadline for submission of NO_x Budget Permits.

4. The Department should apply the monitoring requirements of the OTR Regulations in a manner consistent with the NO_x Allowance Regulations.

EXHIBITS TO

INTERNATIONAL PAPER COMPANY'S

COMMENTS TO PROPOSED OTR REGULATIONS

federal register

Tuesday
October 27, 1998

Part II

Environmental Protection Agency

40 CFR Parts 51, 72, 75, and 96
Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule

Exhibit A

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 75, and 96

[FRL-6171-2]

RIN 2060-AH10

Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In accordance with the Clean Air Act (CAA), today's action is a final rule to require 22 States and the District of Columbia to submit State implementation plan (SIP) revisions to prohibit specified amounts of emissions of oxides of nitrogen (NO_X)—one of the precursors to ozone (smog) pollution—for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States.

Ground-level ozone has long been recognized, in both clinical and epidemiological research, to affect public health. There is a wide range of ozone-induced health effects, including decreased lung function (primarily in children active outdoors), increased respiratory symptoms (particularly in highly sensitive individuals), increased hospital admissions and emergency room visits for respiratory causes (among children and adults with pre-existing respiratory disease such as asthma), increased inflammation of the lung, and possible long-term damage to the lungs.

In today's action, EPA finds that sources and emitting activities in each of the 22 States and the District of Columbia (23 jurisdictions) emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour and 8-hour ozone national ambient air quality standards (NAAQS), or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States. Further, by today's action, EPA is requiring each of the affected upwind jurisdictions (sometimes referred to as upwind States) to submit SIP revisions prohibiting those amounts of NO_X emissions which significantly contribute to downwind air quality problems. The reduction of those NO_X emissions will bring NO_X emissions in each of those States to within the resulting statewide NO_X emissions budget levels established in today's rule. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. These States will be able to choose any mix of pollution-reduction measures that will achieve the required reductions.

EFFECTIVE DATES: This rule is effective December 28, 1998. The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 28, 1998.

ADDRESSES: Dockets containing information relating to this rulemaking (Docket No. A-96-56 and Docket No. A-9-35) are available for public inspection at the Air and Radiation Docket and Information Center (6102), US Environmental Protection Agency, 401 M Street SW, room M-1500, Washington, DC 20460, telephone (202) 260-7548, between 8:00 a.m. and 4:00 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to Kimber S. Scavo, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC 27711, telephone (919) 541-3354; e-mail: scavo.kimber@epa.gov. Please refer to **SUPPLEMENTARY INFORMATION** below for a list of contacts for specific subjects described in today's action.

SUPPLEMENTARY INFORMATION:

Availability of Related Information

Documents related to the Ozone Transport Assessment Group (OTAG) are available on the Agency's Office of Air Quality Planning and Standards' (OAQPS) Technology Transfer Network (TTN) via the web at http://www.epa.gov/ttn/. If assistance is needed in accessing the system, call the help desk at (919) 541-5384 in Research Triangle Park, NC. Documents related to OTAG can be downloaded directly from OTAG's webpage at http://www.epa.gov/ttn/otag/. The OTAG's technical data are located at http://www.iceis.mcnc.org/OTAGDC. The notice of proposed rulemaking for this final action, the supplemental notice of proposed rulemaking, and associated documents are located at http://epa.gov/ttn/oarpg/otagsip.html. Information related to Sections II, Weight of Evidence Determination of Covered States, and IV, Air Quality Assessment, can be obtained in electronic form from the following EPA website: http://www.epa.gov/scram001/regmodcenter/t28.htm. Information related to Section III, Determination of Budgets, may be found on the following EPA website: http://www.epa.gov/capi. All information in electronic form may also be found on diskettes that have been placed in the docket to this rulemaking.

For Additional Information

For technical questions related to the air quality analyses, please contact Norm Possiel; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD-14, Research Triangle Park, NC 27711, telephone (919) 541-5692. For legal questions, please contact Howard J. Hoffman, Office of General Counsel, 401 M Street SW, MC-2344, Washington, DC 20460, telephone (202) 260-5892. For questions concerning the statewide emissions budget revisions, please contact Laurel Schultz; Office of Air Quality Planning and Standards; Emissions, Monitoring, and Analysis Division; MD-14, Research Triangle Park, NC 27711, telephone (919) 541-5511. For questions concerning SIP reporting requirements, please contact Bill Johnson, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC 27711, telephone (919) 541-5245. For questions concerning the model cap-and-trade rule, please contact Rob Lacount, Office of Atmospheric Programs, Acid Rain Division, MC-6204J, 401 M Street SW, Washington, DC 20460, telephone (202) 564-9122. For questions concerning the regulatory cost analysis of electricity generating sources, please contact Ravi Srivastava, Office of Atmospheric Programs, Acid Rain Division, MC-6204J, 401 M Street SW, Washington DC 20460, telephone (202) 564-9093. For questions concerning the regulatory cost analysis of other stationary sources and questions concerning the Regulatory Impact Analysis (RIA), please contact Scott Mathias, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC 27711, telephone (919) 541-5310.

Outline

CFR Revisions and Additions

I. Background

A. Summary of Rulemaking and Affected States

By notice of proposed rulemaking (NPR, proposal, or "proposed SIP call") (62 FR 60318, November 7, 1997) and by supplemental notice (SNPR or supplemental proposal) (63 FR 25902, May 11, 1998), EPA proposed to find that NO_X emissions from sources and emitting activities (sources) in 23 jurisdictions (hereinafter also referred to as States) will significantly contribute to nonattainment of the 1-hour and 8-hour ozone NAAQS, or will interfere with maintenance of the 8-hour NAAQS, in one or more downwind States throughout the Eastern United States. The EPA based these proposals on data generated by OTAG, public comments, and other relevant information. Today's final action confirms that proposed finding. It also requires, under CAA section 110(a)(1) and 110(k)(5), that the 23 jurisdictions adopt and submit SIP revisions that, in order to assure that their SIPs meet the requirements of section 110(a)(2)(D)(i)(I), contain provisions adequate to prohibit sources in those States from emitting NO_X in amounts that "contribute significantly to nonattainment in, or interfere with maintenance by," a downwind State. The 23 jurisdictions are: Alabama, Connecticut, Delaware, District of Columbia, Georgia, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, Missouri, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

Each of these States and the District of Columbia is required to adopt and submit by September 30, 1999, a SIP revision. The SIP revision must contain measures that will assure that sources in the State reduce their NO_X emissions sufficiently to eliminate the amounts of NO_X emissions that contribute significantly to nonattainment, or that interfere with maintenance, downwind. By eliminating these amounts of NO_X emissions, the control measures will assure that the remaining NO_X emissions will meet the level identified in today's rule as the State's NO_X emissions budget. For simplicity, this final rule may refer to the amounts that such SIP provisions must prohibit in order to meet the statute as the "significant amounts" of NO_X emissions. After prohibiting these significant amounts of NO_X, the remaining amounts emitted by sources in the covered States will not "significantly contribute to nonattainment, or interfere with maintenance by," a downwind State, under section 110(a)(2)(D)(i)(I). Section II.C, Weight-of-Evidence Determination of Covered States, describes how EPA determined which States include sources that emit NO_X in amounts of concern (the "covered" States), and Sections II.D, Cost Effectiveness of Emissions Reductions; II.E, Comparison of Upwind and Downwind Costs; and III, Determination of Budgets, describe how EPA determined the significant amounts of emissions and the resulting statewide emissions budgets for the States identified above. Section IV, Air Quality Assessment, discusses air quality analyses conducted by EPA which help confirm the decisions and requirements set forth in this rulemaking. Section V, NO_X Control Implementation and Budget Achievement Dates, primarily discusses the dates by which (1) the States must submit SIP revisions in response to today's action, (2) the sources must implement the measures the States choose for the purpose of prohibiting the significant amounts of NO_X, and (3) the States are projected to achieve the budget levels. Section VI, SIP Criteria and Emissions Reporting Requirements, describes the SIP requirements themselves.

The SIP requirements permit each State to determine what measures to adopt to prohibit the significant amounts and hence meet the necessary emissions budget. Consistent with OTAG's recommendations to achieve

is highly cost effective. The EPA then determined a set of controls on NO_X sources that would cost no more than an average of $2,000 per ton reduced. Specifically, EPA determined that one set of these controls would include a cap-and-trade program for (i) electricity generating boilers and turbines larger than 25 Mwe ("large EGUs"), and (ii) large non-electricity generating industrial boilers and turbines ("large non-EGU boilers and turbines"). The application of an emission rate of 0.15 lb/mmBtu and 1995–1996 utilization for EGUs and 60 percent for large non-EGUs to the emissions projected to occur in 2007 including growth and CAA measures, led to the determination of the amounts to be reduced. The remaining amount is a State's budget.

The EPA further determined that additional highly cost-effective controls are also available for cement manufacturing sources and internal combustion engines. On the basis of reasonable assumptions concerning growth to the year 2007, EPA then determined the amounts of emissions from these source categories that would be eliminated with those controls.

The EPA further determined that there were no other controls on other NO_X sources that qualify as highly cost effective (although several controls are reasonably cost-effective).

On the basis of the determinations just described for the various source categories, EPA determined an amount of NO_X emissions that may be eliminated through these highly cost-effective measures. Because EPA had also determined that the NO_X emissions from the affected upwind States have a large and/or frequent impact on downwind nonattainment or maintenance problems, EPA concludes that the amount of NO_X emissions from those States that can be eliminated through application of highly cost-effective control measures contributes significantly to nonattainment or maintenance problems downwind.

Under section 110(a)(2)(D)(i)(I), the SIP must include "adequate provisions prohibiting" sources from emitting these "amounts." Because no highly cost-effective controls are available to eliminate the remaining amounts of NO_X emissions, EPA concludes that those emissions do not contribute significantly to downwind nonattainment or maintenance problems. As indicated below and in Section III, there are cost-effective alternatives available to States that choose not to adopt all of the highly cost-effective measures on which EPA based its selection of the significant amounts of NO_X emissions.

To implement EPA's determinations, each affected upwind State is required to submit for EPA approval SIP controls projected to be sufficient, by the year 2007, to eliminate the amount of NO_X emissions in the State that EPA determined contributes significantly to nonattainment. The EPA determined this amount of reductions, for each affected upwind State, as follows: EPA first determined the amount of NO_X emissions in that State by the year 2007, based on assumptions concerning both growth and emissions controls that are required under the CAA or that will be implemented due to Federal actions (the "2007 base case"). Second, EPA applied the control measures identified as highly cost effective to the 2007 base case amount for the appropriate source categories. The amount of NO_X emissions remaining in the State after application of controls to the affected source categories constitutes the 2007 budget. The difference between the 2007 base case and the 2007 budget is the amount of NO_X emissions in that State by the year 2007 that EPA has determined to contribute significantly to nonattainment and that, therefore, the SIPs must prohibit.

The upwind State's SIP revision due in response to today's action must provide controls that, on the basis of the same assumptions (including concerning growth) made by EPA in determining the budget, would limit NO_X emissions in the year 2007 to no more than the 2007 budget. The State has full discretion in selecting the controls, so that it may choose any set of controls that would assure achievement of the budget.

As EPA stated in the NPR:

> States are not constrained to adopt measures that mirror the measures EPA used in calculating the budgets. In fact, EPA believes that many control measures not on the list relied upon to develop EPA's proposed budgets are reasonable—especially those, like enhanced vehicle inspection and maintenance programs, that yield both NO_X and VOC emissions reductions.[27] Thus, one State may choose to primarily achieve emissions reductions from stationary sources while another State may focus emission reductions from the mobile source sector. (62 FR 60328).

The EPA believes that its overall approach derives further support from the mandate in section 110(a)(2)(D) that each SIP include provisions prohibiting "any source or other type of emissions activity within the State from emitting any air pollutant in amounts that adversely affect downwind areas. The phrase "any source or other type of emissions activity" may be interpreted to require that the SIP regulate all sources of emissions to assure that the total amount of emissions generated within the State does not adversely affect downwind areas. By its terms, the phrase covers all emitters of any kind because every emitter—stationary, mobile, or area—may be considered a "source or other type of emissions activity." This interpretation is consistent with the legislative history of the phrase. Prior to the CAA Amendments of 1990, the predecessor to section 110(a)(2)(D), which was section 110(a)(2)(E), referred to "any stationary source within the State." In the 1990 Amendments, Congress revised the phrase to read as it currently does. A Committee Report explained, "Where prohibitions in existing section 110(a)(2)(E) apply only to emissions from a single source, the amendment includes "any other type of emissions activity," which makes the provision effective in prohibiting emissions from, for example, multiple sources, mobile sources, and area sources." V Leg. Hist. 8361, S. Rep. No. 228, 101st Cong., 1st Sess. 21 (1989).

For reasons explained below, if an upwind State chooses to achieve all or a portion of the required reductions from large EGUs or large non-EGU boilers and turbines, then the SIP must include a mass emissions limitation for those sources computed with reference to certain growth assumptions and the emission rate limits chosen by the State. The EPA recommends that this mass limitation, or cap, be accompanied by a trading program. Any such cap-and-trade program must be established by May 1, 2003. If the State chooses to achieve all or a portion of the required reductions from other sources, then the State must implement controls, by the year 2003, on those other sources that are projected to achieve the required level of reductions, based on certain assumptions (including growth), in the year 2007. The controls on these other sources may be rate-based, and no emissions cap on them is required. By the year 2007, any applicable mass emissions limitation for large EGUs or large non-EGU boilers and turbines must continue to be met, and any applicable controls on other sources must continue to be implemented. The amount of the 2007 overall budget is used to compute the level of controls that would result in the appropriate amount of emissions reductions, given assumptions concerning, for example,

[27] As indicated in the NPR, EPA considers that measures may be reasonable in light of their reduction of VOC and NO_X emissions, even though their cost-effectiveness in terms of cost per NO_X emissions removed is relatively high (62 FR 60346–48).

control technology (RACT); and units with a capacity less than or equal to 250 MmBtu/hr and with emissions less than or equal to 1 ton per day were considered small sources for which no reduction would be assumed in the budget. In the SNPR, EPA specifically invited comment on the size cutoffs and on treating large industrial combustion sources (greater than 250 mmBtu or approximately 1 ton per day) at control levels equal to that for EGUs (63 FR 25909). As described below, this approach has been modified somewhat in response to comments and further analysis.

a. Proposed Control Assumptions.

Comments: Some comments supported EPA's proposed approach of assuming 70 percent and RACT controls in its calculation of the budgets. Numerous comments were received stating that the 70 percent reduction is inappropriate, may not be cost-effective and may not be achievable, especially for the following industries: cement plants; municipal waste combustors; certain pulp and paper operations, including lime kilns and recovery furnaces; glass manufacturing; steel plants; and some industrial boilers. Some comments suggested a control level of 60 percent rather than 70 percent. On the other hand, one commenter stated that SCR and SNCR are applicable and have been installed on hundreds of industrial sources.

Response: The EPA generally agrees that 70 percent emissions reduction is not appropriate for all large sources or all large source categories, even though SCR and SNCR are applicable and cost-effective for many sources. Instead of applying a one-size-fits-all percentage reduction to all large non-EGU sources, the specific emissions decreases assigned to each of these source categories for purposes of budget calculation in the final SIP Call rulemaking reflect the specific controls available for each source category that achieve the most emissions reductions at costs less than an average of $2,000 per ton. As described elsewhere in this notice, EPA's analysis results in calculating budget reductions ranging from 30 percent to 90 percent for several source categories and no controls to several other source categories.

b. Small Source Exemption.

Comments: In general, commenters were supportive of EPA including a cutoff level as part of the budget calculation; however, there were many suggestions on what the cutoff should be. The EPA received numerous comments supporting the proposed cutoff level of 25 MWe for EGUs, which is approximately equivalent to 250 mmBtu/hr or one ton per day. In addition, EPA received a few comments supporting a 250 mmBtu/hr cutoff for non-EGU point sources. Commenters indicated that the levels were appropriate and that it was important to be consistent with cutoff levels in the OTC's NO_X trading program. The Ozone Transport Commission (OTC) comprises the States of Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, the northern counties of Virginia, and the District of Columbia. In September 1994, the OTC adopted a memorandum of understanding (MOU) to achieve regional emission reductions of NO_X. These reductions are in addition to previous OTC state efforts to control NO_X emissions, which included the installation of reasonably available control technology. The OTC's NO_X trading program requires utility and nonutility boilers greater than 25 MWe or 250 mmBtu to reduce emissions in order to meet a NO_X budget and allows emissions trading consistent with that budget. These NO_X reductions will take place in two phases, the first phase beginning on May 1, 1999 and the second phase on May 1, 2003.

Some comments suggested assuming budget controls on units less than or equal to 25 MWe at RACT levels without a cutoff level. Others supported EPA's proposal of assuming no additional controls on these sources. Some comments suggested exempting medium-sized non-EGU sources.

Many commenters supported the general 1 ton per day exemption contained in the NPR and SNPR. However, a few comments suggested a more stringent cutoff level of 50–100 tons per year, similar to definitions of "major source" in the CAA. One commenter recommended a less stringent level of 5 tons per day cutoff level.

A few comments suggest using tons per day as the primary criterion to define large- and medium-sized non-EGU sources, rather than boiler capacity. This approach would exempt, for example, industrial boilers that exceed the 250 mmBtu capacity, but which emit less than one ton per day on average. The EPA's proposed approach considers a source large if heat input capacity data are available and exceed the 250 mmBtu capacity criterion, regardless of its average daily emissions. In support of this approach, commenters stated that industrial operations do not usually operate at or near capacity, while EGUs often do.

A few commenters indicated that the OTAG recommendations for turbines and internal combustion engines (in terms of horsepower cutoff levels) be used. OTAG had recommended cutoff levels of 4,000 horsepower for stationary internal combustion engines and 10,000 horsepower for gas turbines.

Response: For reasons described below and in the NPR (62 FR 60354), EPA believes that the cutoff levels of 250 mmBtu/hr and 1 ton per day for large non-EGU point sources are appropriate. The EPA selected 250 mmBtu/hr and 1 ton per day primarily because this is approximately equivalent to the 25 MWe cutoff used for the EGU sector. Emission decreases from sources smaller than the heat input capacity cutoff level, and that emit less than 1 ton of NO_X per ozone season day, are not assumed as part of the budget calculation; these sources are included in the budget at baseline levels.

The EPA believes that the 1 ton per day exclusion contained in the NPR and SNPR is appropriate and necessary. This level allows today's rulemaking to focus, for the purpose of calculating the budget, on the group of emission sources that contribute the vast majority of emissions, while at the same time avoids assuming emissions reductions from a very large number of smaller sources (as described in the following paragraph). In taking today's first major step towards reducing regional transport of NO_X, EPA does not believe that emission reductions from these small sources need to be assumed. This approach provides more certainty and fewer administrative obstacles while still achieving the desired environmental results. Although other cutoff levels were suggested by commenters, EPA believes that the cutoff levels described above strike the appropriate balance so that reasonable controls may be applied by States to a sufficient but manageable number of sources to efficiently achieve the needed emission reductions.

Most small sources emit less than 100 tons of NO_X per year. Although their total emissions are low, small sources account for about 90 percent of the total number of point sources. Thus, not assuming controls on these sources at the present time would greatly limit administrative complexity and reporting costs. This common-sense approach results in reducing the non-EGU population potentially affected by the ozone transport rule from more than 13,000 sources estimated in the NPR and SNPR to under 1,200.

Although a few comments suggested using tons per day, not capacity (MWe or mmBtu/hr), for setting cutoff levels, EPA chose primarily to use capacity indicators. This approach is consistent

with EPA's proposed core group definition:

• Those who felt that the core group definition was too limiting; and

• Those who felt that the core group definition was too inclusive.

a. Commenters Who Felt the Core Group Should Not Be Changed. Commenters who supported the concept of a core group generally and the cut-offs proposed by EPA specifically explained that the cut-offs are consistent with the Acid Rain Program and that the use of a core group will minimize inconsistencies that could impede establishment of interstate trading. Commenters also added that the program should provide the flexibility to allow additional sources to opt-in on an individual basis or for States to bring in additional sources on a categorical basis. Some of these commenters added that the timing for bringing in these sources or source categories should be dependent upon the ability of the source or source category to accurately monitor emissions. For some source categories it might be appropriate to bring them in at the start of the program; for others, it might be necessary to wait until their ability to quantify emissions has improved.

Commenters who generally supported the concept of a core group of sources as it was defined in the SNPR did have several specific concerns. One commenter noted that while the SNPR preamble clearly explained that the rule only included fossil-fuel-fired units, the rule itself was not clear on this issue. Another commenter suggested that because the proposed definition differentiated between electrical generating units and non-electrical generating units it excluded sources that should be in the trading program such as cogeneration facilities that consisted of boilers greater than 250 mmBtu/hr that served electric generating units with a rating of less than 25 MWe.

The EPA agrees that the establishment of a core group will help facilitate interstate trading as well as compliance with the emissions budget. If there is not some minimum group of trading participants, sources that are in the program will have less of an opportunity to trade allowances and realize the economic benefits of trading. In addition, by ensuring that most of the emissions from industries covered by the trading program are included in a capped system, the trading program can be simplified because concerns about load shifting to uncapped sources is minimized. The EPA also agrees that making the cut-offs consistent with existing regulatory programs helps to minimize conflicts with existing regulatory programs. The EPA also agrees with both of the concerns raised by the commenters. Therefore the regulatory definition of unit has been clarified to make it clear that a unit must be fossil-fuel fired. The EPA has also added a clarification to the definition of fossil-fuel fired. This clarification is intended to define a baseline period for determining if a unit is fossil-fuel fired. The revised definition states that fossil-fuel fired means the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel comprises more than 50 percent of the annual heat input on a Btu basis. An existing unit is considered fossil-fuel fired if it meets this criterion for any year since 1990 (or if not operating since 1990 during the last year of operation). A new unit is considered fossil-fuel fired if it is projected to meet this criterion or, if after operation begins, it does meet this criterion.

In addition, to address the concern about excluding cogeneration facilities that are greater than 250 mmBtu/hr that serve electric generating units with a rating of less than 25 MWe, the applicability has been changed to include all units greater than 250 mmBtu/hr, regardless of how much electricity they generate.

b. Commenters Who Felt the Core Group Should Be Expanded. Commenters who felt the trading program should be expanded focused on a number of areas. Several commenters argued generally that the program should allow any source to participate if the source can document that emissions reductions have been achieved. A number of commenters mentioned as examples the inclusion of medium-sized and smaller stationary sources in the RECLAIM program. A few commenters argued that the addition of certain sources is needed for consistency with the OTC NO_X Budget Rule. Other commenters opposed the core group concept because they believe that regulation of low-level and local sources in the Northeast is an essential step in solving the ozone problem. Others argued that excluding non-utility sources from the trading program unfairly excludes these sources from least-cost compliance options. Some commenters suggested specific categories of units that should be allowed to, but not required to, participate in the trading program. These included:

(1) Municipal waste combustors;

(2) Internal combustion engines;

(3) Process units;

(4) Units for which the output product is not comparable to other units on which the allocations are based, such as process heaters, hazardous waste incinerators, process vents and nitric acid plants.

The EPA believes that many of the concerns about the core source definition stem from a misunderstanding of its purpose. The core sources definition was intended to indicate the minimum applicability requirements that a State rule would have to include to participate in a larger multi-state program that EPA would help to administer. It was not intended to limit individual States from including more sources (as long as the sources meet certain criteria further explained below) in the larger multi-state program (63 FR 25924). Nor was it intended to prohibit a State (or group of States) from developing its own trading program with a more limited applicability.

If, however, a State or group of States developed a trading program that did not meet the minimum requirements set forth in the model NO^X Budget Trading Program, such as minimum core source applicability, EPA would not participate in the administration of such a trading program. This is because it would not be administratively cost-efficient for EPA to manage multiple trading programs with a variety of applicability and other requirements designed to address the same issue.

The EPA is not expanding the core source group to include any additional sources because EPA believes that this decision is better left to the states. Therefore the model rule will allow a State to expand the applicability of the trading program to include additional stationary sources if the sources meet certain criteria. These criteria include the ability to accurately and consistently monitor and report emissions and the ability to identify a party responsible for ensuring that monitoring and reporting requirements are met, for authorizing allowance transfers and for ensuring compliance. The EPA's rationale for setting these minimum criteria are set forth in the preamble to the SNPR (63 FR 25923). Also, EPA addresses issues specifically related to the monitoring requirements for these sources in Section D.3 of today's preamble.

There are two mechanisms that can be used to include more sources in the program. One is for a State to expand the applicability criteria to include other source categories; the other is to give individual sources the ability to opt-in.

States that choose to expand the applicability criteria can do so (1) by lowering the applicability threshold for source categories that are already part of

alternative compliance options for units with low NO_X mass emissions, explained below. Combustion turbines smaller than 100 MWe are also likely candidates to qualify for the alternative compliance option explained below.

The Acid Rain Program exempts cyclone boilers with a maximum continuous steam flow at 100 percent load of greater than 1060 thousand lb/hr from NO_X control requirements under part 76. These units were exempted because one of the primary criteria in title IV of the CAA for setting emissions limitations under part 76 was comparability of cost with low NO_X emission controls on boilers categorized as group 1 boilers under Title IV (large tangentially fired and dry bottom, wall fired). There is no such criterion in the CAA applicable to this rulemaking. Also, since the emission reductions required by this rulemaking are more substantial than the emission reductions required under part 76 [70], the cost per ton of reducing NO_X emission reductions is correspondingly higher. Therefore, applicability cutoffs that were relevant in the part 76 rulemaking are not relevant in this rulemaking.

In response to the comment that small electrical generators less than 25 MWe should be exempt from the NO_X Budget Trading Program, they were proposed to be exempt and will be exempt under the final model rule. They do still have the option of opting into the program if they choose to do so.

In the SNPR (63 FR 25926), EPA took comment on allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per ozone season), that because of their size would be included in the trading program, to be exempt from the requirements of the trading program. In general commenters supported this concept. One commenter who supported the concept also added that it would be important to ensure that there were adequate requirements to assure that the individual sources who took advantage of this option demonstrated compliance with their unit-specific caps. The commenters who disagreed with this option expressed concern that a State's budget could be exceeded if emissions from these units were not accounted for.

Based on the comments received EPA continues to believe that it is appropriate to offer States the option of providing units that are above the applicability threshold but that have a very low potential to emit an alternative compliance option. This option would allow units that meet the requirements described below to be exempt from the requirements to hold allowances, and to comply with quarterly reporting requirements. In order to address the concern that sources must demonstrate compliance with their individual cap, EPA has added specific requirements that sources must meet in order to use this alternative compliance option.

Units that use this option would be required to:

(1) have a federally enforceable permit restricting ozone season emissions to less than 25 tons;

(2) keep on site records demonstrating that the conditions of the permit were met, including restrictions on operating time;

(3) report hours of operation during the ozone season to the permitting authority on an annual basis.

A unit choosing to use this compliance option would be required to determine the appropriate restrictions on its operating time by dividing 25 tons by the unit's maximum potential hourly NO_X mass emissions. The unit's maximum potential hourly NO_X mass emissions would be determined by multiplying the highest default emission rate for any fuel that the unit burned (using the default emission rates, in part 75.19 of this chapter) by the maximum rated hourly heat input of the unit (as defined in part 72 of this chapter).

States would be allowed, but not required, to incorporate this alternative compliance option into their SIPs. The EPA does agree that if a State does incorporate this option into the SIP, it would have to account for the emissions under its budget. Thus a State that chose to use this option would have to either:

(1) Subtract the total amount of potential emissions permitted to be emitted using this approach from the trading portion of the budget before the remaining portion of the trading budget is allocated to the trading participants; or (2) Offset the difference between total amount of potential emissions permitted to be emitted using this approach and the 2007 base year inventory emissions for these same sources with additional reductions outside of the trading portion of the budget.

If States choose not to incorporate this alternative compliance option into their SIPs, or if they choose to incorporate it exactly as it is set forth in the model rule, it will not affect the streamlined approval of the trading rule portion of the SIP. A State may choose to require an alternative means of ensuring that the potential to emit for units utilizing the alternative means of compliance is limited to less than 25 tons, however if a State deviates from the model rule in this way, the SIP will no longer receive streamlined approval.

2. Mobile/Area Sources

The proposed rule did not include mobile or area sources in the trading program, but solicited comment on expanding applicability to include these sources, or to include credits generated by these sources, in the trading program. Mobile and area sources were not included in the proposed trading rule due to EPA's concerns related to ensuring that reductions were real, developing and implementing procedures for monitoring emissions, and identifying responsible parties for the implementation of the program and associated emissions reductions.

The EPA received comment from State and local government, industry and coalitions of industry, and environmental groups regarding the inclusion of mobile and area sources in the program. Comments focused on the following main areas: inclusion or exclusion of mobile and area sources, subcategories of mobile sources for inclusion, and the use of pilot programs to foster innovation.

Some commenters urged EPA to include mobile and area sources with as few restrictions as possible in the trading program, primarily on an opt-in or voluntary basis. These commenters argued that excluding mobile sources would reduce the potential scope and benefits of the trading by placing a large portion of States' NO_X inventory outside the scope of the trading program. They noted that the existence of RECLAIM protocols for mobile and area source credit generation demonstrated that EPA's quantification, verification, and administration concerns were misplaced.

The majority of commenters, however, indicated that mobile sources should not be included at this time and that the model rule should not be delayed to address concerns related to inclusion of these sources. Some commenters argued against ever including mobile and area sources in the program. One State argued that inclusion of mobile and area sources would destroy the integrity of the program since mobile and area source reductions are not necessarily real, verifiable and quantifiable, failing to display a level of certainty comparable to those sources included in the trading program. A few commenters indicated that mobile sources were inherently unsuited to a capped system, since the difficulties of measuring emissions from these sources precludes their inclusion in a budget.

[70] The lowest emission rate required under part 76 is 0.40 lbs/mmBtu.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in appendix A of part 60 of this chapter.

Serial number means, when referring to NO_X allowances, the unique identification number assigned to each NO_X allowance by the Administrator, under § 96.53(c).

Source means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the CAA. For purposes of section 502(c) of the CAA, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the 48 contiguous States and the District of Columbia specified in § 51.121 of this chapter, or any non-federal authority in or including such States or the District of Columbia (including local agencies, and Statewide agencies) or any eligible Indian tribe in an area of such State or the District of Columbia, that adopts a NO_X Budget Trading Program pursuant to § 51.121 of this chapter. To the extent a State incorporates by reference the provisions of this part, the term "State" shall mean the incorporating State. The term "State" shall have its conventional meaning where such meaning is clear from the context.

State trading program budget means the total number of NO_X tons apportioned to all NO_X Budget units in a given State, in accordance with the NO_X Budget Trading Program, for use in a given control period.

Submit or serve means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any "submission," "service," or "mailing" deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Title V operating permit means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

Title V operating permit regulations means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

Ton or tonnage means any "short ton" (i.e., 2,000 pounds). For the purpose of determining compliance with the NO_X Budget emissions limitation, total tons for a control period shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with subpart H of this part, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed to equal zero tons.

Unit means a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Unit load means the total (i.e., gross) output of a unit in any control period (or other specified time period) produced by combusting a given heat input of fuel, expressed in terms of:

(1) The total electrical generation (MWe) produced by the unit, including generation for use within the plant; or

(2) In the case of a unit that uses heat input for purposes other than electrical generation, the total steam pressure (psia) produced by the unit, including steam for use by the unit.

Unit operating day means a calendar day in which a unit combusts any fuel.

Unit operating hour or *hour of unit operation* means any hour (or fraction of an hour) during which a unit combusts any fuel.

Utilization means the heat input (expressed in mmBtu/time) for a unit. The unit's total heat input for the control period in each year will be determined in accordance with part 75 of this chapter if the NO_X Budget unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the Administrator for the unit if the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

§ 96.3 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.
hr—hour.
Kwh—kilowatt hour.
lb—pounds.
mmBtu—million Btu.
MWe—megawatt electrical.
ton—2000 pounds.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
O_2—oxygen.

§ 96.4 Applicability.

(a) The following units in a State shall be NO_X Budget units, and any source that includes one or more such units shall be a NO_X Budget source, subject to the requirements of this part:

(1) Any unit that, any time on or after January 1, 1995, serves a generator with a nameplate capacity greater than 25 MWe and sells any amount of electricity; or

(2) Any unit that is not a unit under paragraph (a) of this section and that has a maximum design heat input greater than 250 mmBtu/hr.

(b) Notwithstanding paragraph (a) of this section, a unit under paragraph (a) of this section shall be subject only to the requirements of this paragraph (b) if the unit has a federally enforceable permit that meets the requirements of paragraph (b)(1) of this section and restricts the unit to burning only natural gas or fuel oil during a control period in 2003 or later and each control period thereafter and restricts the unit's operating hours during each such control period to the number of hours (determined in accordance with paragraph (b)(1)(ii) and (iii) of this section) that limits the unit's potential NO_X mass emissions for the control period to 25 tons or less. Notwithstanding paragraph (a) of this section, starting with the effective date of such federally enforceable permit, the unit shall not be a NO_X Budget unit.

(1) For each control period under paragraph (b) of this section, the federally enforceable permit must:

(i) Restrict the unit to burning only natural gas or fuel oil.

(ii) Restrict the unit's operating hours to the number calculated by dividing 25 tons of potential NO_X mass emissions by the unit's maximum potential hourly NO_X mass emissions.

(iii) Require that the unit's potential NO_X mass emissions shall be calculated as follows:

(A) Select the default NO_X emission rate in Table 2 of § 75.19 of this chapter that would otherwise be applicable assuming that the unit burns only the type of fuel (i.e., only natural gas or only fuel oil) that has the highest default NO_X emission factor of any type of fuel that the unit is allowed to burn under the fuel use restriction in paragraph (b)(1)(i) of this section; and

(B) Multiply the default NO_X emission rate under paragraph (b)(1)(iii)(A) of this section by the unit's maximum rated hourly heat input. The owner or operator of the unit may petition the permitting authority to use a lower value for the unit's maximum rated hourly heat input than the value as defined under § 96.2. The permitting authority may approve such lower value if the owner or operator demonstrates that the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and that such lower value is representative, of the unit's current capabilities because

modifications have been made to the unit, limiting its capacity permanently.

(iv) Require that the owner or operator of the unit shall retain at the source that includes the unit, for 5 years, records demonstrating that the operating hours restriction, the fuel use restriction, and the other requirements of the permit related to these restrictions were met.

(v) Require that the owner or operator of the unit shall report the unit's hours of operation (treating any partial hour of operation as a whole hour of operation) during each control period to the permitting authority by November 1 of each year for which the unit is subject to the federally enforceable permit.

(2) The permitting authority that issues the federally enforceable permit with the fuel use restriction under paragraph (b)(1)(i) and the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section will notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority includes such restrictions. The permitting authority will also notify the Administrator in writing of each unit under paragraph (a) of this section whose federally enforceable permit issued by the permitting authority is revised to remove any such restriction, whose federally enforceable permit issued by the permitting authority includes any such restriction that is no longer applicable, or which does not comply with any such restriction.

(3) If, for any control period under paragraph (b) of this section, the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section is removed from the unit's federally enforceable permit or otherwise becomes no longer applicable or if, for any such control period, the unit does not comply with the fuel use restriction under paragraph (b)(1)(i) of this section or the operating hours restriction under paragraphs (b)(1)(ii) and (iii) of this section, the unit shall be a NO_X Budget unit, subject to the requirements of this part. Such unit shall be treated as commencing operation and, for a unit under paragraph (a)(1) of this section, commencing commercial operation on September 30 of the control period for which the fuel use restriction or the operating hours restriction is no longer applicable or during which the unit does not comply with the fuel use restriction or the operating hours restriction.

§ 96.5 Retired unit exemption.

(a) This section applies to any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired.

(b)(1) Any NO_X Budget unit, other than a NO_X Budget opt-in source, that is permanently retired shall be exempt from the NO_X Budget Trading Program, except for the provisions of this section, §§ 96.2, 96.3, 96.4, 96.7 and subparts E, F, and G of this part.

(2) The exemption under paragraph (b)(1) of this section shall become effective the day on which the unit is permanently retired. Within 30 days of permanent retirement, the NO_X authorized account representative (authorized in accordance with subpart B of this part) shall submit a statement to the permitting authority otherwise responsible for administering any NO_X Budget permit for the unit. A copy of the statement shall be submitted to the Administrator. The statement shall state (in a format prescribed by the permitting authority) that the unit is permanently retired and will comply with the requirements of paragraph (c) of this section.

(3) After receipt of the notice under paragraph (b)(2) of this section, the permitting authority will amend any permit covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (b)(1) and (c) of this section.

(c) *Special provisions.* (1) A unit exempt under this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect. The owners and operators of the unit will be allocated allowances in accordance with subpart E of this part.

(2)(i) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(ii) A unit exempt under this section and located at a source that is required, or but for this exemption would be required, to have a non-title V permit shall not resume operation unless the NO_X authorized account representative of the source submits a complete NO_X Budget permit application under § 96.22 for the unit not less than 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) prior to the later of May 1, 2003 or the date on which the unit is to first resume operation.

(3) The owners and operators and, to the extent applicable, the NO_X authorized account representative of a unit exempt under this section shall comply with the requirements of the NO_X Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit that is exempt under this section is not eligible to be a NO_X Budget opt-in source under subpart I of this part.

(5) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time prior to the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(6) *Loss of exemption.* (i) On the earlier of the following dates, a unit exempt under paragraph (b) of this section shall lose its exemption:

(A) The date on which the NO_X authorized account representative submits a NO_X Budget permit application under paragraph (c)(2) of this section; or

(B) The date on which the NO_X authorized account representative is required under paragraph (c)(2) of this section to submit a NO_X Budget permit application.

(ii) For the purpose of applying monitoring requirements under subpart H of this part, a unit that loses its exemption under this section shall be treated as a unit that commences operation or commercial operation on the first date on which the unit resumes operation.

§ 96.6 Standard requirements.

(a) *Permit Requirements.* (1) The NO_X authorized account representative of each NO_X Budget source required to have a federally enforceable permit and each NO_X Budget unit required to have a federally enforceable permit at the source shall:

(i) Submit to the permitting authority a complete NO_X Budget permit application under § 96.22 in accordance

binding on the new alternate NO_X authorized account representative and the owners and operators of the NO_X Budget source and the NO_X Budget units at the source.

(c) *Changes in the owners and operators.* (1) In the event a new owner or operator of a NO_X Budget source or a NO_X Budget unit is not included in the list of owners and operators submitted in the account certificate of representation, such new owner or operator shall be deemed to be subject to and bound by the account certificate of representation, the representations, actions, inactions, and submissions of the NO_X authorized account representative and any alternate NO_X authorized account representative of the source or unit, and the decisions, orders, actions, and inactions of the permitting authority or the Administrator, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a NO_X Budget source or a NO_X Budget unit, including the addition of a new owner or operator, the NO_X authorized account representative or alternate NO_X authorized account representative shall submit a revision to the account certificate of representation amending the list of owners and operators to include the change.

§ 96.13 Account certificate of representation.

(a) A complete account certificate of representation for a NO_X authorized account representative or an alternate NO_X authorized account representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the NO_X Budget source and each NO_X Budget unit at the source for which the account certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the NO_X authorized account representative and any alternate NO_X authorized account representative.

(3) A list of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source.

(4) The following certification statement by the NO_X authorized account representative and any alternate NO_X authorized account representative: "I certify that I was selected as the NO_X authorized account representative or alternate NO_X authorized account representative, as applicable, by an agreement binding on the owners and operators of the NO_X Budget source and each NO_X Budget unit at the source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the NO_X Budget Trading Program on behalf of the owners and operators of the NO_X Budget source and of each NO_X Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the permitting authority, the Administrator, or a court regarding the source or unit."

(5) The signature of the NO_X authorized account representative and any alternate NO_X authorized account representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the account certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 96.14 Objections concerning the NO_X authorized account representative.

(a) Once a complete account certificate of representation under § 96.13 has been submitted and received, the permitting authority and the Administrator will rely on the account certificate of representation unless and until a superseding complete account certificate of representation under § 96.13 is received by the Administrator.

(b) Except as provided in § 96.12(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission of the NO_X authorized account representative shall affect any representation, action, inaction, or submission of the NO_X authorized account representative or the finality of any decision or order by the permitting authority or the Administrator under the NO_X Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any NO_X authorized account representative, including private legal disputes concerning the proceeds of NO_X allowance transfers.

Subpart C—Permits

§ 96.20 General NO_X Budget trading program permit requirements.

(a) For each NO_X Budget source required to have a federally enforceable permit, such permit shall include a NO_X Budget permit administered by the permitting authority.

(1) For NO_X Budget sources required to have a title V operating permit, the NO_X Budget portion of the title V permit shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such title V operating permits regulations shall include, but are not limited to, those provisions addressing operating permit applications, operating permit application shield, operating permit duration, operating permit shield, operating permit issuance, operating permit revision and reopening, public participation, State review, and review by the Administrator.

(2) For NO_X Budget sources required to have a non-title V permit, the NO_X Budget portion of the non-title V permit shall be administered in accordance with the permitting authority's regulations promulgated to administer non-title V permits, except as provided otherwise by this subpart or subpart I of this part. The applicable provisions of such non-title V permits regulations may include, but are not limited to, provisions addressing permit applications, permit application shield, permit duration, permit shield, permit issuance, permit revision and reopening, public participation, State review, and review by the Administrator.

(b) Each NO_X Budget permit (including a draft or proposed NO_X Budget permit, if applicable) shall contain all applicable NO_X Budget Trading Program requirements and shall be a complete and segregable portion of the permit under paragraph (a) of this section.

§ 96.21 Submission of NO_X Budget permit applications.

(a) *Duty to apply.* The NO_X authorized account representative of any NO_X Budget source required to have a federally enforceable permit shall submit to the permitting authority a complete NO_X Budget permit application under § 96.22 by the applicable deadline in paragraph (b) of this section.

(b)(1) For NO_X Budget sources required to have a title V operating permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's title V operating permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(2) For NO_X Budget sources required to have a non-title V permit:

(i) For any source, with one or more NO_X Budget units under § 96.4 that commence operation before January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget units to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before May 1, 2003.

(ii) For any source, with any NO_X Budget unit under § 96.4 that commences operation on or after January 1, 2000, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 covering such NO_X Budget unit to the permitting authority at least 18 months (or such lesser time provided under the permitting authority's non-title V permits regulations for final action on a permit application) before the later of May 1, 2003 or the date on which the NO_X Budget unit commences operation.

(c) *Duty to reapply.* (1) For a NO_X Budget source required to have a title V operating permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's title V operating permits regulations addressing operating permit renewal.

(2) For a NO_X Budget source required to have a non-title V permit, the NO_X authorized account representative shall submit a complete NO_X Budget permit application under § 96.22 for the NO_X Budget source covering the NO_X Budget units at the source in accordance with the permitting authority's non-title V permits regulations addressing permit renewal.

§ 96.22 Information requirements for NO_X Budget permit applications.

A complete NO_X Budget permit application shall include the following elements concerning the NO_X Budget source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the NO_X Budget source, including plant name and the ORIS (Office of Regulatory Information Systems) or facility code assigned to the source by the Energy Information Administration, if applicable;

(b) Identification of each NO_X Budget unit at the NO_X Budget source and whether it is a NO_X Budget unit under § 96.4 or under subpart I of this part;

(c) The standard requirements under § 96.6; and

(d) For each NO_X Budget opt-in unit at the NO_X Budget source, the following certification statements by the NO_X authorized account representative:

(1) "I certify that each unit for which this permit application is submitted under subpart I of this part is not a NO_X Budget unit under 40 CFR 96.4 and is not covered by a retired unit exemption under 40 CFR 96.5 that is in effect."

(2) If the application is for an initial NO_X Budget opt-in permit, "I certify that each unit for which this permit application is submitted under subpart I is currently operating, as that term is defined under 40 CFR 96.2."

§ 96.23 NO_X Budget permit contents.

(a) Each NO_X Budget permit (including any draft or proposed NO_X Budget permit, if applicable) will contain, in a format prescribed by the permitting authority, all elements required for a complete NO_X Budget permit application under § 96.22 as approved or adjusted by the permitting authority.

(b) Each NO_X Budget permit is deemed to incorporate automatically the definitions of terms under § 96.2 and, upon recordation by the Administrator under subparts F, G, or I of this part, every allocation, transfer, or deduction of a NO_X allowance to or from the compliance accounts of the NO_X Budget units covered by the permit or the overdraft account of the NO_X Budget source covered by the permit.

§ 96.24 Effective date of initial NO_X Budget permit.

The initial NO_X Budget permit covering a NO_X Budget unit for which a complete NO_X Budget permit application is timely submitted under § 96.21(b) shall become effective by the later of:

(a) May 1, 2003;

(b) May 1 of the year in which the NO_X Budget unit commences operation, if the unit commences operation on or before May 1 of that year;

(c) The date on which the NO_X Budget unit commences operation, if the unit commences operation during a control period; or

(d) May 1 of the year following the year in which the NO_X Budget unit commences operation, if the unit commences operation on or after October 1 of the year.

§ 96.25 NO_X Budget permit revisions.

(a) For a NO_X Budget source with a title V operating permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

(b) For a NO_X Budget source with a non-title V permit, except as provided in § 96.23(b), the permitting authority will revise the NO_X Budget permit, as necessary, in accordance with the permitting authority's non-title V permits regulations addressing permit revisions.

Subpart D—Compliance Certification

§ 96.30 Compliance certification report.

(a) *Applicability and deadline.* For each control period in which one or more NO_X Budget units at a source are subject to the NO_X Budget emissions limitation, the NO_X authorized account representative of the source shall submit to the permitting authority and the Administrator by November 30 of that year, a compliance certification report for each source covering all such units.

(b) *Contents of report.* The NO_X authorized account representative shall include in the compliance certification report under paragraph (a) of this section the following elements, in a format prescribed by the Administrator, concerning each unit at the source and subject to the NO_X Budget emissions limitation for the control period covered by the report:

(1) Identification of each NO_X Budget unit;

monitoring NO_X mass. This includes all systems required to monitor NO_X emission rate, NO_X concentration, heat input, and flow, in accordance with §§ 75.72 and 75.76.

(2) Install all monitoring systems for monitoring heat input, if required under § 96.76 for developing NO_X allowance allocations.

(3) Successfully complete all certification tests required under § 96.71 and meet all other provisions of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraphs (a)(1) and (2) of this section.

(4) Record, and report data from the monitoring systems under paragraphs (a)(1) and (2) of this section.

(b) *Compliance dates.* The owner or operator must meet the requirements of paragraphs (a)(1) through (a)(3) of this section on or before the following dates and must record and report data on and after the following dates:

(1) NO_X Budget units for which the owner or operator intends to apply for early reduction credits under § 96.55(d) must comply with the requirements of this subpart by May 1, 2000.

(2) Except for NO_X Budget units under paragraph (b)(1) of this section, NO_X Budget units under § 96.4 that commence operation before January 1, 2002, must comply with the requirements of this subpart by May 1, 2002.

(3) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on an annual basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) May 1, 2002; or

(ii) The earlier of:

(A) 180 days after the date on which the unit commences operation or, (B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(4) NO_X Budget units under § 96.4 that commence operation on or after January 1, 2002 and that report on a control season basis under § 96.74(d) must comply with the requirements of this subpart by the later of the following dates:

(i) The earlier of:

(A) 180 days after the date on which the unit commences operation or,

(B) For units under § 96.4(a)(1), 90 days after the date on which the unit commences commercial operation.

(ii) However, if the applicable deadline under paragraph (b)(4)(i) section does not occur during a control period, May 1; immediately following the date determined in accordance with paragraph (b)(4)(i) of this section.

(5) For a NO_X Budget unit with a new stack or flue for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2) or (b)(3) of this section or subpart I of this part:

(i) 90 days after the date on which emissions first exit to the atmosphere through the new stack or flue;

(ii) However, if the unit reports on a control season basis under § 96.74(d) and the applicable deadline under paragraph (b)(5)(i) of this section does not occur during the control period, May 1 immediately following the applicable deadline in paragraph (b)(5)(i) of this section.

(6) For a unit for which an application for a NO_X Budget opt in permit is submitted and not denied or withdrawn, the compliance dates specified under subpart I of this part.

(c) *Reporting data prior to initial certification.* (1) The owner or operator of a NO_X Budget unit that misses the certification deadline under paragraph (b)(1) of this section is not eligible to apply for early reduction credits. The owner or operator of the unit becomes subject to the certification deadline under paragraph (b)(2) of this section.

(2) The owner or operator of a NO_X Budget under paragraphs (b)(3) or (b)(4) of this section must determine, record and report NO_X mass, heat input (if required for purposes of allocations) and any other values required to determine NO_X Mass (e.g. NO_X emission rate and heat input or NO_X concentration and stack flow) using the provisions of § 75.70(g) of this chapter, from the date and hour that the unit starts operating until all required certification tests are successfully completed.

(d) *Prohibitions.* (1) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with § 96.75.

(2) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(3) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter except as provided for in § 75.74 of this chapter.

(4) No owner or operator of a NO_X Budget unit or a non-NO_X Budget unit monitored under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under § 96.5 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The NO_X authorized account representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 96.71(b)(2).

§ 96.71 Initial certification and recertification procedures

(a) The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter, except that:

(1) If, prior to January 1, 1998, the Administrator approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.17 of this chapter, the NO_X authorized account representative shall resubmit the petition to the Administrator under § 96.75(a) to determine if the approval applies under the NO_X Budget Trading Program.

(2) For any additional CEMS required under the common stack provisions in § 75.72 of this chapter, or for any NO_X concentration CEMS used under the provisions of § 75.71(a)(2) of this chapter, the owner or operator shall

meet the requirements of paragraph (b) of this section.

(b) The owner or operator of a NO_X Budget unit that is not subject to an Acid Rain emissions limitation shall comply with the following initial certification and recertification procedures, except that the owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 shall also meet the requirements of paragraph (c) of this section and the owner or operator of a unit that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall also meet the requirements of paragraph (d) of this section. The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation, but requires additional CEMS under the common stack provisions in § 75.72 of this chapter, or that uses a NO_X concentration CEMS under § 75.71(a)(2) of this chapter also shall comply with the following initial certification and recertification procedures.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each monitoring system required by subpart H of part 75 of this chapter (which includes the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter. The owner or operator shall ensure that all applicable certification tests are successfully completed by the deadlines specified in § 96.70(b). In addition, whenever the owner or operator installs a monitoring system in order to meet the requirements of this part in a location where no such monitoring system was previously installed, initial certification according to § 75.20 is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in a certified monitoring system that the Administrator or the permitting authority determines significantly affects the ability of the system to accurately measure or record NO_X mass emissions or heat input or to meet the requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system according to § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that the Administrator or the permitting authority determines to significantly change the flow or concentration profile, the owner or operator shall recertify the continuous emissions monitoring system according to § 75.20(b) of this chapter. Examples of changes which require recertification include: replacement of the analyzer, change in location or orientation of the sampling probe or site, or changing of flow rate monitor polynomial coefficients.

(3) *Certification approval process for initial certifications and recertification.* (i) *Notification of certification.* The NO_X authorized account representative shall submit to the permitting authority, the appropriate EPA Regional Office and the permitting authority a written notice of the dates of certification in accordance with § 96.73.

(ii) *Certification application.* The NO_X authorized account representative shall submit to the permitting authority a certification application for each monitoring system required under subpart H of part 75 of this chapter. A complete certification application shall include the information specified in subpart H of part 75 of this chapter.

(iii) Except for units using the low mass emission excepted methodology under § 75.19 of this chapter, the provisional certification date for a monitor shall be determined using the procedures set forth in § 75.20(a)(3) of this chapter. A provisionally certified monitor may be used under the NO_X Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system or component thereof under paragraph (b)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system or component thereof, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete certification application by the permitting authority.

(iv) *Certification application formal approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (b)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system which meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the NO_X Budget Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* A certification application will be considered complete when all of the applicable information required to be submitted under paragraph (b)(3)(ii) of this section has been received by the permitting authority. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the NO_X authorized account representative must submit the additional information required to complete the certification application. If the NO_X authorized account representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (b)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system or component thereof does not meet the performance requirements of this part, or if the certification application is incomplete and the requirement for disapproval under paragraph (b)(3)(iv)(B) of this section has been met, the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system or component thereof shall not be considered valid quality-assured data beginning with the date and hour of provisional certification. The owner or operator shall follow the procedures for loss of certification in paragraph (b)(3)(v) of this section for each monitoring system or component thereof which is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.72(b).

(v) *Procedures for loss of certification.* If the permitting authority issues a notice of disapproval of a certification application under paragraph

(b)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (b)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each hour of unit operation during the period of invalid data beginning with the date and hour of provisional certification and continuing until the time, date, and hour specified under § 75.20(a)(5)(i) of this chapter:

(1) For units using or intending to monitor for NO_X emission rate and heat input or for units using the low mass emission excepted methodology under § 75.19 of this chapter, the maximum potential NO_X emission rate and the maximum potential hourly heat input of the unit.

(2) For units intending to monitor for NO_X mass emissions using a NO_X pollutant concentration monitor and a flow monitor, the maximum potential concentration of NO_X and the maximum potential flow rate of the unit under section 2.1 of appendix A of part 75 of this chapter;

(B) The NO_X authorized account representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (b)(3)(i) and (ii) of this section; and

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(c) Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19 of this chapter. The owner or operator of a gas-fired or oil-fired unit using the low mass emissions excepted methodology under § 75.19 of this chapter shall meet the applicable general operating requirements of § 75.10 of this chapter, the applicable requirements of § 75.19 of this chapter, and the applicable certification requirements of § 96.71 of this chapter, except that the excepted methodology shall be deemed provisionally certified for use under the NO_X Budget Trading Program, as of the following dates:

(1) For units that are reporting on an annual basis under § 96.74(d):

(i) For a unit that has commences operation before its compliance deadline under § 96.71(b), from January 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commences operation after its compliance deadline under § 96.71(b), the date of submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for permitting authority review, or

(2) For units that are reporting on a control period basis under § 96.74(b)(3)(ii) of this part:

(i) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted before May 1, from May 1 of the year of the submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(ii) For a unit that commenced operation before its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, from May 1 of the year following submission of the certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority review; or

(iii) For a unit that commences operation after its compliance deadline under § 96.71(b), where the unit commences operation before May 1, from May 1 of the year that the unit commenced operation, until the completion of the period for the permitting authority's review.

(iv) For a unit that has not operated after its compliance deadline under § 96.71(b), where the certification application is submitted after May 1, but before October 1st, from the date of submission of a certification application for approval to use the low mass emissions excepted methodology under § 75.19 of this chapter until the completion of the period for the permitting authority's review.

(d) Certification/recertification procedures for alternative monitoring systems. The NO_X authorized account representative representing the owner or operator of each unit applying to monitor using an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall apply for certification to the permitting authority prior to use of the system under the NO_X Trading Program. The NO_X authorized account representative shall apply for recertification following a replacement, modification or change according to the procedures in paragraph (b) of this section. The owner or operator of an alternative monitoring system shall comply with the notification and application requirements for certification according to the procedures specified in paragraph (b)(3) of this section and § 75.20(f) of this chapter.

§ 96.72 Out of control periods.

(a) Whenever any monitoring system fails to meet the quality assurance requirements of appendix B of part 75 of this chapter, data shall be substituted using the applicable procedures in subpart D, appendix D, or appendix E of part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.71 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the system or component. The data measured and recorded by the system or component shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the initial certification or recertification procedures in § 96.71 for each disapproved system.

§ 96.73 Notifications.

The NO_X authorized account representative for a NO_X Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.