Regional Office when making the submittals.

3. Final Rule

After taking into account the comments submitted in response to the May 11, 1998 proposal, EPA today is promulgating emission inventory reporting requirements for States subject to the NO_X SIP call. The regulatory text appears in 40 CFR 51.122, and the main emission reporting requirements are summarized in Table VI–1 below.

TABLE VI–1.—SUMMARY OF NO_X REPORTING REQUIREMENTS

If you own or operate	and	then, your State must report to EPA the source's
A point source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season [2] emissions. 1. triennially [3,5]. 2. for 2007 [5].
A point source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [4]. 2. triennially [5]. 3. for 2007 [5].
An area source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. triennially. 2. for 2007.
An area source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [6]. 2. triennially. 3. for 2007.
A mobile source	You are not subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. triennially. 2. for 2007.
A mobile source	You are subject to regulations relied on to achieve the NO_X reductions required in this SIP call [1].	Ozone season emissions. 1. annually [6]. 2. triennially. 3. for 2007.

[1] The EPA considers the State to rely on regulations to achieve the NO_X reductions required if those regulations require reductions beyond those reflected in the base case 2007 inventory.
[2] Ozone season is May 1 through September 30.
[3] Triennial reporting (which is every 3 years) starts with emissions occurring in 2002.
[4] Annual reporting starts with emissions occurring in 2003.
[5] Triennial and 2007 reports for point sources contain additional data elements not required in the annual reports.
[6] The data elements in the annual report for area and mobile sources satisfy the reporting requirements for these source categories for the triennial and 2007 reports. However, the triennial reports start with emissions occurring in the year 2002 and the annual reports start with emissions occurring in the year 2003.

4. Data Elements to be Reported

In addition to reporting the NO_X emissions values shown in Table VI–1, the State must report other critical data necessary to generate and validate these values. This includes data used to identify source categories such as site name, location and (source classification code) SCC codes. It also includes data used to generate the NO_X emissions values such as fuel heat content and activity level. The specific data elements required for each source category are further defined in 40 CFR 51.122.

5. 2007 Report

The EPA is requiring that States submit to EPA for the year 2007 a special onetime statewide NO_X emissions inventory from all NO_X sources (point, area, and mobile) within the State. The data reporting requirements are identical to the reporting requirements for the triennial inventories, and this reporting requirement is being imposed to allow evaluation of whether the budget is met in 2007. This one-time special inventory is necessary because the ordinary 3-year reporting cycle does not fall in the year 2007.

States which must submit the 2007 inventory may project incremental changes in emissions from 2007 to 2008 to allow the 2008 inventory requirement to be more easily met and to reduce the burden on States which must submit full NO_X inventories for consecutive years, i.e., 2007 and 2008.

The EPA received comments saying that EPA should not require the special report in 2007 due to increased resources required but rather should adjust the schedule of the triennial reports so that a triennial report year will fall on 2007. Alternatively, the EPA could eliminate the 2008 triennial report. The EPA has considered these alternatives, but believes that the schedule which was proposed is necessary to maintain consistency with other EPA reporting requirements and is not unnecessarily burdensome.

6. Ozone Season Reporting

The EPA is requiring that the States provide ozone-season (i.e., May 1 through September 30) inventories for the sources for which the State reports annual, triennial and 2007 emissions. The ozone season emissions may be calculated from annual data by prorating emissions from the ozone season by utilization factors that must be reported and that are further defined in 40 CFR 51.122. For the triennial and 2007 reports, ozone season emissions from all NO_X source categories within the State, controlled or uncontrolled, must be reported. The EPA is requiring that each State provide its ozone season calculation method to EPA for approval.

7. Data Reporting Procedures

When submitting a formal NO_X budget emissions report and associated data, the State should formally notify the appropriate EPA Regional Office of its activities. States are required to report emissions data in an electronic format to one of the locations given below. Several options are available for data reporting. The State may choose to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) using the AIRS facility subsystem (AFS) format for point sources. (This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified.) A second option is for the State to convert its emissions data into the Emission Inventory Improvement Program/ Electronic Data Interchange (EIIP/EDI) format. This file can then be made available to any requestor, either using E-mail, floppy disk, or value added network, or can be placed on a file transfer protocol (FTP) site. As a third option, the State may submit its emissions data in a proprietary format based on the EIIP data model. For the last two options, the terms ''submitting'' and ''reporting'' data are defined as either providing the data in the EIIP/EDI format or the EIIP based data model proprietary format to EPA, Office of Air Quality Planning and Standards, Emission Factors and Inventory Group, directly or notifying that group that the data are available in the specified format and at a specific electronic location (e.g., FTP site). A fourth option for annual reporting (not for third year reports) is to have sources submit the data directly to EPA. This option will be available to any source in a State that is both participating in an approved trading program and that has agreed to submit data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

For the latest information on data reporting procedures, call the EPA Info Chief help desk at (919) 541–5285 or e-mail to info.chief@epamail.epa.gov.

8. Confidential Data

Emissions data being requested in today's action are not considered confidential by the EPA (See 42 U.S.C. 7414). However, some States may restrict the release of certain types of data, such as process throughput data. Where Federal and State requirements are inconsistent, the EPA Regional Office should be consulted for final reconciliation.

C. Timeline

The reporting requirements fit into the general time line summarized below:

September 30, 1999—Deadline for SIP submissions in response to this SIP call.

2002—The first triennial emissions inventory report must be submitted for ozone season emissions for this year. States must collect emissions inventory information for all NO_X sources in the State. This report must be submitted by December 31, 2003 (i.e., 12 months after the end of the calendar year for which the data are collected.)

May 1, 2003—The SIP measures required to achieve the NO_X reductions must be implemented by this date.

2003—The first annual emissions inventory report must be submitted for certain ozone season NO_X emissions for this year. Specifically, States must collect emissions information regarding all sources for which the State is relying on measures to meet its NO_X budget (''SIP call sources''). This report is due December 31, 2004.

2004—The second annual emissions inventory report must be submitted for ozone season emissions from SIP call sources for this year. This report is due December 31, 2005.

2005—The second triennial report must be submitted for ozone season emissions from all NO_X sources for this year. The report is due December 31, 2006.

2006—The third annual report must be submitted for ozone season emissions from SIP call sources in the State for this year. This report is due December 31, 2007.

2007—The special year 2007 emission inventory report for ozone season emissions from all NO_X sources in the State must be submitted for this year. This report is due December 31, 2008. The EPA will assess whether States have met their budgets in the year 2007.

2008—The third triennial emissions inventory report must be submitted for ozone season emissions for this year. This report is due December 31, 2009.

Annual and triennial reports must continue to be submitted in future years beyond 2008 in order for the EPA to track compliance with the budget or any revisions to the budget that may occur after 2007.

VII. NO_X Budget Trading Program

A. General Background

In the November 7, 1997 proposed rulemaking, EPA offered to develop and administer a multi-state NO_X trading program to assist States in the achievement of their budgets. Today's notice sets forth a model program on which States may choose to base their SIP submittal. The trading program employs a cap on total emissions in order to ensure that emissions reductions under the transport rulemaking are achieved and maintained, while providing the cost effectiveness of a market-based system. States can voluntarily choose to participate in the NO_X Budget Trading Program by adopting the final model rule, which is a fully approvable control strategy for achieving over 90 percent of the emissions reductions required under the transport rulemaking.

B. NO_X Budget Trading Program Rulemaking Overview

Prior to publication of the proposed NO_X Budget Trading Program, EPA held two public workshops to solicit comments and suggestions from States and other stakeholders on a NO_X cap-and-trade program. Over 150 people participated in each of the workshops. To facilitate meaningful comments from these participants, EPA developed papers on critical issues that were made available for review prior to each workshop. These papers discussed major issues relevant to developing a NO_X Budget Trading Rule, delineated options and, in some cases, offered recommendations. The issues associated with each working paper were presented at the workshops, followed by open discussion periods allowing workshop participants to comment and discuss each issue. Input from workshop participants was extremely helpful in drafting the proposed NO_X Budget Trading Program. In addition to input gained from the workshop process, the NO_X Budget Trading Program builds directly upon the Ozone Transport Commission's NO_X Budget Program and recommendations from the OTAG's Trading and Incentives Workgroup. On May 11, 1998, EPA published the proposed NO_X Budget Trading Program as a part of the supplemental notice for the proposed ozone transport rulemaking. The final NO_X Budget Trading Rule published in today's notice reflects changes that have been made in response to comments received on the May 11, 1998 proposal.

C. General Design of NO_X Budget Trading Program

1. Appropriateness of Trading Program

The EPA proposed that a voluntary market-based program be established as one possible means for a State to meet its NO_X emissions reduction obligations under the NO_X SIP call. The vast majority of commenters, including States, industry, and environmental groups, supported a market approach over traditional ''command and control'' mechanisms to fulfill reduction requirements. However, many commenters argued that the proposed State budgets, based on the cost-effectiveness of an emission limit of 0.15 lb/mmBtu for large combustion sources, are too stringent to provide sufficient surplus allowances to support a market. These commenters argued that cost and technological constraints would prevent regulated sources from over-controlling, thus reducing the pool of allowances and the cost savings EPA predicts would accompany trading. However, several other commenters stated that the trading program was the most cost-effective means to reduce emissions and would in fact generate sufficient allowances for trading. These commenters noted that all but the highest emitting coal-fired units can achieve this rate, and that many sources are able to achieve emission limits significantly below 0.15 lb/mmBtu. They also argued that, at least in the early years of the trading program, the growth factors used to determine the budgets will lead to a less stringent emission reduction requirement than 0.15 lb/mmBtu.

The EPA notes that nothing requires a State to impose a 0.15 lb/mmBtu limit on its large combustion sources. The States will select in their SIPs which sources to regulate and the type of regulation to impose in order to achieve their NO_X budgets. The EPA believes that trading for large combustion sources under a budget based on 0.15 lb/mmBtu is a feasible, highly cost-effective means of meeting a State's budget. The Agency believes that 0.15 lb/mmBtu can easily be achieved by gas and oil-fired boilers. In fact, more than 50 percent of gas and oil-fired boilers already operate at NO_X levels below 0.15 lb/mmBtu and should therefore easily be able to generate excess allowances if trading is allowed. The EPA recognizes that for coal-fired boilers to operate at or below a 0.15 lb/mmBtu emission limit, selective catalytic reduction (SCR) will generally be necessary. Under a trading scenario, however, if one coal-fired boiler is able to emit below 0.15 lb/mmBtu by installing SCR, it can provide excess allowance to another coal-fired boiler and obviate the need for that boiler to install SCR. (For further technical justification for the feasibility of 0.15 lb/mmBtu, see Section III.B.2 of this preamble.) In summary, EPA concludes that, should a State elect to control large combustion sources with a budget based on an emission rate of 0.15 lb/mmBtu, ample allowances would exist to sustain a market under the NO_X Budget Trading Program.

Several of the commenters who did not support the trading program proposed by EPA were generally wary of the use of market approaches for environmental regulation, especially in the context of ozone attainment strategies, citing concerns that emissions in existing nonattainment areas may increase under such a program. The EPA, however, believes that a trading program is an appropriate mechanism to achieve the NO_X reductions required under the SIP call. The EPA proposed the trading program in the SNPR based on recommendations from OTAG, experience from the Ozone Transport Commission, and EPA's public workshops held in November and December 1997. This trading program was designed to mitigate transport of ozone and its precursors to facilitate attainment and maintenance of the ozone NAAQS. Analyses in conjunction with the SIP call show that implementation of a trading program with a uniform control level results in no significant changes in the location of emissions reductions than would result from a non-trading scenario (''Supplemental Ozone Transport Rulemaking Regulatory Analysis'', April 1998, page 2–19). The NO_X reductions required by the SIP call will significantly lower background levels of ozone and can be coupled with local measures to achieve further NO_X reductions, as well as VOC reductions, where necessary to reach attainment. States concerned with contribution by local sources in the trading program are free to limit emissions from particular sources by imposing source-specific emission limits where deemed necessary.

2. Alternative Market Mechanisms

The SNPR proposed to establish a model cap-and-trade program for certain large combustion sources. This proposed program employs a cap on total emissions to ensure achievement and maintenance of the emissions reductions required under the NO_X SIP call while providing the flexibility and cost effectiveness of a market-based system. Several commenters supported EPA's recommendation for a cap-and-trade program. Several others complained that EPA's focus on a capped trading program was inappropriate, citing OTAG's recognition that NO_X market systems could also be implemented without an emissions cap. As a result, these commenters felt that EPA could not make a cap a prerequisite to approval of a State trading program. They suggested that EPA recognize that a rate-based program can be part of a viable SIP, perhaps by outlining parameters of an acceptable alternative program or working with OTAG States to develop a rate-based program that would better accommodate future growth. Another issue raised by a few commenters was that the trading program would either conflict with or would ignore existing local or State-based trading programs.

The EPA first reiterates that the model program is voluntary (63 FR 25918). In providing a cap-and-trade program as a streamlined means by which to comply with the NO_X SIP call, EPA does not preclude implementation of other solutions. The purpose of the trading program is to provide a compliance mechanism that capitalizes on a proven means of cost effectively meeting a specific emissions budget that the Agency will assist States in administering.

As OTAG concluded, the procedures for a cap-and-trade program have already been developed and used successfully, whereas procedures for other types of multi-state trading programs have not been developed and implemented to the same degree. Therefore, EPA does not have the same level of experience or established protocols to follow in the design and administration of other types of trading programs. The OTAG did encourage development of provisions to implement other types of trading programs, and EPA recognizes that these alternative trading programs may be appropriate in some circumstances.

However, EPA recommends a cap-and-trade program for purposes of the NO_X SIP call because, by limiting total NO_X emissions to the level determined to address the interstate transport problem, a cap better ensures achievement and maintenance of the environmental goal articulated in the NO_X SIP call. In contrast, under a non-cap trading program, the addition of new sources to the regulated sector or increased utilization of existing sources could increase total emissions above the level determined to address transport, even though a NO_X rate limit is met.

States, however, have the flexibility to respond as they see fit to meet their emissions budgets established under the NO_X SIP call. States are free to pursue other regulatory mechanisms or include other types of trading programs in their SIPs, whether newly created or already existing, on the condition that they meet EPA's SIP approval criteria as delineated for the NO_X SIP call. These criteria mandate that regulatory requirements for boilers, turbines and combined cycle units that are greater than 250 mmBtu or that serve electrical generators that are greater than 25 MWe be expressed in one of three ways: (1) In terms of mass emissions; (2) in terms of emissions rates that when multiplied by the affected sources' maximum operating capacity would meet the tonnage component of the emissions budget for these sources; or (3) an alternative approach for expressing regulatory requirements, provided the State demonstrates, to EPA's satisfaction, that its alternative provides equivalent or greater assurance than options (1) or (2) that seasonal emissions budgets will be attained and maintained. For further information regarding SIP approvability criteria, see Section VI.A.2.b of this preamble.

3. State Adoption of Model Rule

In the SNPR, EPA proposed that States electing to participate in the NO_X Budget Trading Program could either adopt the model rule by reference or develop State regulations in accordance with the model rule. The few commenters on this issue were primarily concerned about lack of guidance by EPA in this area for State adoption of the model rule and the potential for deviation from the model rule in the State-adopted rules. This section clarifies EPA's intent in issuing a model rule and distinguishes between sections of the model rule that State rules must mirror, and those that States may choose to alter or eliminate while maintaining a SIP that is approvable for purposes of joining the NO_X Budget Trading Program.

a. Process for Adoption. One commenter suggested that rather than adopting the NO_X Budget Trading Program, it should be sufficient for each State to include a statement in its SIP declaring that the State will participate in the Federal program, along with a demonstration of the authority for the State to do so. This would leave the details in the Federal rule and avoid differences that could arise through each State adopting its own rule. However, EPA does not have the statutory authority under title I to promulgate a Federal cap-and-trade program to achieve a State's SIP call budget unless the State fails to respond adequately to the SIP call. The EPA understands the commenter's concern regarding differences among State rules to implement the NO_X Budget Trading Program, and intends to ensure consistency as explained in the following Section.

The EPA's intent in issuing a model rule for the NO_X Budget Trading Program is to provide States with a model program that serves as an approvable strategy for achieving more than 90 percent of the required reductions under the NO_X SIP call. States choosing to participate in the program will be responsible for adopting State regulations to support the NO_X Budget Trading Program, and submitting those rules as part of the SIP. As articulated in the proposed rulemaking (63 FR 25920), there are two legal alternatives for a State to use in joining the NO_X Budget Trading Program: incorporate 40 CFR part 96 by reference into the State's regulations, or adopt State regulations that mirror 40 CFR part 96 but for the variations and omissions described below.

b. Model Rule Variations. The EPA would like to clarify the variations and omissions from the model rule that are acceptable in a State rule, to provide States flexibility while still ensuring the environmental results and administrative feasibility of the program. More specifically, EPA will clarify those variations that maintain a State's eligibility for the streamlined SIP approval associated with adoption of the model rule, those changes that will require more extensive review by EPA prior to approval, and those changes that are not acceptable for incorporation into the NO_X Budget Trading Program.

In order for a SIP revision to be approved for State participation in the NO_X Budget Trading Program, on a streamlined basis or otherwise, the State rule should not deviate from the model rule except in the areas of applicability, NO_X allowance allocation methodology, and early reduction credit methodology (all of which are described briefly in the following paragraphs and in more detail in subsequent Sections of today's notice). Deviations from the model rule regarding allocation methodologies and early reduction credit methodologies as defined in this Section do not impact a State's eligibility for streamlined approval of its SIP with respect to the NO_X Budget Trading Program. However, some deviations regarding applicability will require more extensive EPA review, as explained below. Changes to program applicability may render a State's rule ineligible for streamlined approval, though the rule would still be eligible for approval after a more thorough EPA review.

State rules that deviate beyond the applicability, allocation, and early reduction credit flexibility provided in the model rule would not be approvable for inclusion in the NO_X Budget Trading Program. SIPs incorporating a trading program that is not approved for inclusion in the broader NO_X Budget Trading Program may still be acceptable for purposes of achieving some or all of a State's obligations under the NO_X SIP call, provided the SIP criteria outlined in Section VI.A.2.b are met. However, only States participating in the NO_X Budget Trading Program would be included in EPA's tracking systems for NO_X emissions and allowances used to administer the multi-state trading program.

For States participating in the NO_X Budget Trading Program, applicability is one of the three main areas in which the State may deviate from the model rule. State rules need to include an applicability section that at least covers the core sources defined in the model rule, but States may allow additional stationary sources to participate in the trading program. These sources must be able to monitor and report emissions in accordance with the model rule, and identify an individual responsible for fulfilling program requirements to be eligible for inclusion. States have three options to expand applicability and one to limit it, as explained in the following paragraphs.

States may choose to expand applicability either by: (1) Including smaller sources in the core source categories, (2) including additional source categories, or (3) providing individual sources the ability to opt in. Expansion of applicability to smaller core sources will maintain the State's eligibility for streamlined SIP approval with regard to the NO_X Budget Trading Program. Including additional source categories beyond the core sources (e.g., municipal waste combustors), however, will require more careful review by EPA in some cases to ensure that the trading program requirements can be met, and therefore preclude streamlined SIP approval otherwise associated with adoption of the model rule. Regarding individual source opt-ins, States have the discretion to determine whether or not to include this provision in their State rule. The opt-in provision is not a prerequisite to approval of a SIP incorporating the NO_X Budget Trading Program. However, if a State does choose to include provisions for opt-in sources, these provisions must mirror those in the model rule. Providing the provisions do so, the SIP remains eligible for streamlined EPA approval.

States may also choose to limit applicability of the trading program by allowing units with a low federally enforceable NO_X emission limit (e.g. 25 tons per control period) to be exempt from trading program requirements. A State may include this exemption provision as it appears in the model rule to allow these sources not to participate in the trading program, or a State may omit the provision. Neither of these actions will interfere with streamlined SIP approval by EPA, provided the exemption provisions mirror the model rule if included in the State rule.

In terms of allocations, States must include an allocation section in their rule, conform to the timing requirements for submission of allocations to EPA that are described in this preamble, and allocate an amount of allowances that does not exceed their State trading program budget. However, States may allocate NO_X allowances to NO_X budget sources according to whatever methodology they choose. The EPA has included an optional allocation methodology in 40 CFR part 96, but States are free to allocate as they see fit within the bounds specified above, and still receive streamlined SIP approval for purposes of the NO_X Budget Trading Program.

Today's final rule also includes an optional methodology in § 96.55(c) that States may use for issuing early reduction credits from the State compliance supplement pools. However, States may distribute the State compliance supplement pool to sources as they wish in accordance with the requirements set forth in 40 CFR 51.121(e)(3) and still receive streamlined SIP approval for purposes of the NO_X Budget Trading Program.

In summary, a State is eligible for streamlined approval of the portion of their SIP incorporating the NO_X Budget Trading Program if the State adopts all the provisions of the model rule (e.g., banking and monitoring provisions) with variations incorporated only in the manner explained in this Section. Streamlined approval requires that applicability extends only to the core sources, or to core sources and smaller sources within the core source categories and that the opt-in provision and the exemption option for sources with a low federally permitted emission limit, if included, mirror those in the model rule. Regarding allocations, eligibility for streamlined approval extends to those State rules whose allocations do not exceed the State trading program budget and are determined in accordance with the timing requirements delineated in the model rule. A State rule is still eligible for approval, but not streamlined approval, if the applicability determination for the NO_X Budget Trading Program extends beyond the core sources to additional source categories, to allow for the additional review necessary to ensure such an extension of applicability is administratively feasible and environmentally sound. A State rule is also eligible for streamlined approval if it includes methodologies for issuing credit from the State compliance supplement pool in accordance with the provisions in 40 CFR 51.121(e)(3). Differences among States in these areas will provide flexibility while not detracting from the operation or implementation of the multi-state trading program. Therefore, variations as explained in this section are acceptable to EPA with assurance that State rules will be sufficiently consistent. In addition, joint implementation of the program with EPA will ensure that once these consistent rules are established, they will be implemented consistently as well.

Several commenters expressed concern that the lack of prohibitions on State-imposed trading restrictions in conjunction with the model rule would lead to variation between States and cripple the trading program. The EPA agrees with commenters that additional restrictions imposed on the trading program by individual States could increase economic costs without providing significant environmental benefit. Therefore, EPA does not believe that any restrictions on trading are necessary, and does not foresee approving State rules that include trading restrictions in SIPs incorporating the NO_X Budget Trading Program. However, to address local air quality problems, a State participating in the NO_X Budget Trading Program may establish permit limitations for specific sources participating in the trading program. The EPA considers such a limitation appropriate given local air quality concerns and does not consider it a trading restriction, and therefore the incorporation of such limitations will not preclude streamlined SIP approval. These sources would still participate in the NO_X Budget Trading Program and the unconstrained market operating in the program, but could not use allowances to exceed their permit limitation; the source would be held to the permitted limit, regardless of how many allowances it holds for the purposes of the trading program. This topic is discussed in more detail in the next Section.

4. Unrestricted Trading Market

a. Geographic Issues. For the NO_X SIP call, EPA is basing the State budgets on the uniform application of reasonable, cost-effective NO_X control measures for each State determined to contribute significantly to nonattainment in a downwind State. The EPA's analyses show that the collective reductions across the region will produce significant air quality benefits across the region. The development of and justification for the State budgets under the NO_X SIP call is described in Section III, Determination of Budgets. Although the analyses in today's final action demonstrate that the collective emissions for the NO_X SIP call region significantly contribute to nonattainment, the location of particular emissions does impact the effects that the emissions have on other areas within the region. Emissions in some locations may cause greater overall effects than emissions from other locations.

In the SNPR, EPA proposed a single trading program allowing all emissions to be traded on a one-for-one basis without restrictions on trading allowances within the SIP call region. The EPA also solicited comment on whether the trading program should attempt to factor in differential effects of NO_X emissions based on the location of the emissions. Possible options for factoring in the differential effects include defining exchange ratios for trades between areas based on the differential effects of emissions between areas, establishing subregions for trading, and/or prohibiting certain trades (63 FR 25902 at 25919).

The Agency received more than fifty comments on this issue from the regulated community, States, and environmental organizations. A number of commenters did support limiting trading by establishing smaller subregions within the SIP call region or establishing trading ratios based on the idea that there are differential effects of NO_X emissions based on the location of the emissions. However, none of these commenters included a complete proposal with a justification or description for the appropriate subregional boundaries or trading ratios. The majority of commenters on this subject favored unrestricted trading within areas having a uniform level of control. Most commenters supporting unrestricted trading stated that restrictions would result in fewer cost-savings without achieving any additional environmental benefit and would increase the administrative burden of implementing the program. They expressed concern that discounts or other adjustments or restrictions would unnecessarily complicate the trading program, and therefore reduce its effectiveness.

Consistent with the proposal, the final model rule is designed to be a single jurisdiction trading program allowing all emissions to be traded on a one-for-one basis, without restrictions or limitations on trading allowances within the trading area. EPA has used the IPM to evaluate the emissions and cost impacts of alternative regulatory options under the SIP call for the electric power sector. These analyses can be found in the RIA. The model has been used to show the level and location of emissions if the SIP call were implemented under a number of different alternatives including unrestricted trading and command-and-control approaches. The results indicate that significant shifts in the location of emissions reductions would not occur with unrestricted trading compared to where the reductions would occur under command-and-control and intrastate only trading scenarios. Based upon the IPM results and EPA's air quality modeling, EPA has chosen a region-wide trading program allowing all emissions to be traded on a one-for-one basis without trading restrictions. EPA's analyses suggest that the net effect of all the trades is that the net emissions will not significantly shift within the region compared to a command-and-control scenario. For this reason, EPA believes that the need for trading subregions or trading ratios that differ from one-for-one are unsubstantiated for the purposes of this SIP call and the NO_X Budget Trading Program.

Although the location of net emissions is not expected to significantly shift as a result of trading, it is possible that a State may identify a specific location (e.g., major NO_X source adjacent to or within an urban center) where NO_X reductions would be particularly beneficial for ozone mitigation. For these situations, a State may establish a specific permit limitation restricting the amount of NO_X that may be emitted from the source. The source would still be included in the trading program but it would not be allowed to emit above the amount specified in the permit limitation regardless of the number of NO_X allowances it may hold. The source would be allowed to trade the allowances it is unable to use. In this way, States will be able to tailor specific attainment strategies within the framework of the NO_X Budget Trading Program without restricting the trading options for most sources included in the program.

b. Episodic Issues. The EPA also received several comments addressing the episodic nature of ozone formation and whether this should be factored into the design of the trading program. Commenters noted that under the NO_X SIP call, which is designed to reduce total NO_X emissions from May through September of each year, it is still possible that NO_X emissions may be relatively higher during ozone episodes compared with NO_X emissions on other days between May and September. In addition, the effect of a unit of emissions may be higher during ozone episodes. To address this concern, the commenters stated that the trading program should provide incentives or safeguards to ensure that NO_X emissions reductions are achieved specifically during ozone episodes. One commenter asserted that emissions could either be capped during ozone episodes or that the trading program could place a premium on the use of NO_X allowances during ozone episodes. The commenter recommended the latter option. The premium would require that sources surrender NO_X allowances at rates greater than 1-to-1 for each ton of NO_X emitted during the ozone episodes.

Consistent with the NO_X SIP call, the NO_X Budget Trading Program focuses on reducing total NO_X emissions from May to September for the jurisdictions that are identified in the NO_X SIP call and that choose to participate in the trading program. Proposals to address NO_X emissions during specific episodes and in specific nonattainment areas are more closely tied to issues affecting individual attainment plans rather than the goal of the NO_X SIP call which is to reduce transport. It would be very difficult to apply the appropriate premium to the individual sources that contribute NO_X emissions affecting specific ozone episodes. The meteorology and source contribution for each ozone episode is different. And in some cases, NO_X emissions and the resulting ozone may be transported for several days before contributing to an ozone violation.

Provisions designed to ensure that NO_X emissions reductions are achieved specifically during ozone episodes are more likely to be effective in controlling NO_X emissions that are released adjacent to or within locations frequently affected with elevated ozone levels. Where a State identifies such a source, EPA believes specific permit limitations are an appropriate and effective method for controlling the source's emissions. As stated in the previous section, EPA believes that States may use permit limitations to tailor specific attainment strategies within the framework of the NO_X Budget Trading Program without restricting the trading options for most sources included in the program. Furthermore, this provides each State more flexibility in establishing its attainment plan rather than applying one approach to address the episodic nature of ozone throughout the SIP call region. Therefore, EPA has not included additional trading restrictions to address ozone episodes in the design of the final NO_X Budget Trading Program.

D. Applicability

1. Core Sources

In the SNPR, EPA proposed that compliance with the emission limitation requirements of the NO_X Budget Trading Rule, i.e., the requirement to hold sufficient NO_X allowances to cover emissions, apply to a core group of large stationary 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 was considered fossil fuel-fired if fossil fuels accounted for more than 50 percent of the unit's heat input on an annual basis. The EPA solicited comment on the appropriateness of the categories included in the core group, whether the size cut-offs should be higher or lower for the source categories, and the appropriateness of including other source categories in the core group. Comments on the concept of a core group fell into three broad categories:

• Those who agreed with the core group concept and who generally agreed 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 the core group in order to include smaller sources or (2) by including additional source categories that are not included in the core group. For instance a State in the OTC might choose to lower the applicability cut-off for electrical generating units to 15 MWe to make the program more consistent with the existing OTC NO_X Budget Program. If a State chose to expand the applicability criteria for source categories already included in the core group this would not affect EPA's streamlined approval of the NO_X Budget Trading program component of the State's SIP.

A State might choose to lower the applicability cut-off for sources in the core group to create different applicability cut-offs for new and existing units. This could help to better facilitate integration with a State's new source review program. The EPA took comment on this concept in the SNPR and received comments both for and against this proposal. Commenters who opposed it suggested that it would be a disincentive to replace old units with new cleaner units. Some of these commenters also noted that expanding the applicability cut-off for all units would provide an incentive to replace these older units. Commenters who favored it suggested that it would be an incentive to make new units as clean as possible. The EPA believes that it is appropriate for States to determine how best to handle the issue of small new units.

Another reason to allow smaller sources to opt-in is to simplify monitoring for situations in which a common stack is shared by a number of units, some of which are affected and some which are not. In this situation the owner or operator would have to either install monitors at each of the affected units, or install monitors at the common stack and at all of the non-affected units, so that the emissions from these units could be deducted from the emissions from the affected units. If the owner or operator is allowed to opt-in the nonaffected unit, they will be able to install one set of monitors at the common stack accounting for the emissions from all of the units.

If a State chose to include additional source categories, EPA would have to review the SIP submittal to ensure that those additional source categories met the minimum criteria for monitoring and reporting emissions and for having a responsible official. As further explained in the SNPR (63 FR 25924), EPA would also have to determine if it could successfully administer a regional trading program with the inclusion of these additional source categories.

In the SNPR, EPA proposed developing a list of specific additional source categories beyond the core group which a State could bring into the trading program without affecting EPA's streamlined approval of the trading component of the SIP. While this concept received general support, none of the commenters provided enough specific support to demonstrate that all of the sources in a given source category could meet the criteria to accurately and consistently monitor emissions. These comments are discussed in Section D.3.

The EPA believes that the opportunity for States to expand the applicability to include additional sources addresses concerns about incompatibility with the applicability requirements of existing programs, such as the OTC Trading Program, as well as concerns that an individual State might want to expand the program to address local ozone problems.

The other mechanism that can be used to broaden the applicability of the program is the individual opt-in procedures in subpart I of part 96. These provisions allow a source to opt-in, if it can meet the monitoring and reporting requirements of part 75. The EPA received a number of comments about the monitoring requirements of part 75 as they related to opt-ins. These comments are addressed in Section D.3 of today's preamble.

In the SNPR (62 FR 25940–25942 and 62 FR 25991–25994), EPA proposed that the individual opt-in provisions would only be applicable to fossil-fuel-fired, stationary boilers, combustion turbines, and combined cycle systems smaller than the applicability cut-offs of 25 MWe or 250 mmBtu/hr. The EPA agrees that the RECLAIM program has demonstrated that many combustion sources that are not included in the core applicability criteria can accurately and consistently monitor NO_X mass emissions using CEM (or other alternative protocols for units with low mass emissions) that are very similar to the provisions in subpart H of part 75. Therefore, in today's action EPA is allowing States to expand the opt-in provisions to include any stationary combustion source that emits to a stack and can meet the monitoring and reporting requirements of subpart H of part 75.

States that choose to add other combustion sources that are not part of the core group would also have to address issues related to allocating allowances for those types of sources. Allocation methodologies that may be appropriate for source categories covered in the core group may not be as applicable for other source categories. For instance, as one commenter noted, an output based allocation methodology might not make as much sense for a municipal waste combustor, since the primary purpose of a municipal waste combustor is to combust waste, not to generate usable output.

c. *Commenters Who Felt the Core Group Is Overly Inclusive.* A number of commenters argued that the burdens associated with including certain source categories would outweigh the benefits and that particular types of sources should therefore be excluded from the core group. Many of these commenters stated that individual sources in these groups should be allowed to opt in where there is a net economic benefit to them to participate rather than mandating inclusion of the source category. Specific categories include: non-utility boilers generally; generators of power for on-site use; combustion turbines exempt from Title IV; small cyclone boilers; combustion turbines below 100 MWe; small, particularly municipal, electric generating units (e.g., those under 25 MWe); and units with low potential to emit as defined by enforceable limits (e.g., peaking units with potential to emit less than 100 tons per year).

The EPA does not believe there is a great distinction between similarly sized utility and non-utility boilers. Both categories of boilers are similar in design, have similar control options and have similar control costs. Therefore, EPA is not excluding large non-utility boilers from the trading program. The EPA believes the same arguments that apply to utility and non-utility boilers also apply to generators of power for on-site use and generators of power for resale. In light of the fact that utility restructuring will provide more opportunities for generators of power for on-site use to resell the power they produce in the future, EPA believes that this distinction is even harder to make. Therefore, EPA is not excluding large generators of power for on-site use from the trading program.

In accordance with title IV of the CAA, the Acid Rain Program exempts simple combustion turbines that commenced commercial operation before November 15, 1990. These units were exempted from the Acid Rain Program because the SO_2 emissions from these units were extremely low. The NO_X emissions from these units are potentially higher; therefore, EPA is not adding a specific exemption for these types of units. However, many of these units are small and/or infrequently operated, so their actual NO_X emissions may be quite low; therefore, some of these units may qualify for the 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.

Several commenters suggested that some categories of mobile sources should be included while other categories should not. Commenters indicated, for example, that it is not feasible to have individual motorists participate in the cap-and-trade program due to the burdens and administrative complexity associated with such a vast number of sources and responsible parties in a trading system. Alternatively, commenters argued that manufacturers, fuel distributors, and fleet owners could be included if they were able to generate surplus emission reductions by going beyond the requirements established by some Federal measures. These commenters specifically cited the low-RVP regulations, the vehicle scrappage guidance, and the locomotive regulations as examples of such Federal measures.

Several commenters who recommended that mobile sources not be included in the program at this time also recommended that EPA sponsor pilot programs in States to study the feasibility of inter-sector trading and to develop mechanisms to address the specific concerns mentioned regarding the inclusion of mobile and area sources. Along similar lines, one industry commenter stated that mobile sources may be appropriate candidates for participation in the trading program only if adequate emission reduction measurement protocols can be developed. Foreseeing this occurrence, some commenters felt that EPA should leave a placeholder in the rule or add a provision that would include mobile and area sources once the mechanisms to address the specific concerns of EPA and others have been developed.

The model trading program that EPA is finalizing today will not include mobile and area sources for the reasons outlined in the SNPR. The EPA concurs with the concerns raised by commenters against the inclusion of mobile and area sources, regarding program integrity, emissions monitoring, and accountability. Most of the proponents of including mobile or area sources listed general reasons for including them such as increasing market efficiency, lowering costs, or simply the existence of RECLAIM protocols to do so. However, these commenters did not provide sufficient information or documentation to support the validity of these assertions, and several acknowledged that the potential for improvement in market efficiency or lower compliance costs was difficult to ascertain. Further, one proponent acknowledged that the RECLAIM protocols are new and not yet extensively utilized.

In fact, a recent audit of the RECLAIM program indicates that the volume of mobile source credits used under the program is very small (only 99 NO_X tons have been converted from mobile source reductions in the last five years). Only 5 requests for conversion of mobile source emission reduction credits to RECLAIM trading credits were approved in 1994, and no further requests had been received as of May 1998. The small amount of credits relative to the significant resource expenditure for the conversion of mobile source credits under the RECLAIM program (i.e., the need for case-by-case review given the variability and complexity of the petitions) suggests that the RECLAIM mobile source protocols and strategy are not yet a cost-effective option for the trading program.

The EPA remains willing to consider adding mobile or area sources to the trading program in the future. Most commenters recommended that the program be opened to mobile or area sources once adequate mechanisms are developed for addressing related concerns. In response to these comments, and those recommending that EPA support pilot programs in States in order to facilitate resolution of the areas of concern for mobile and area sources, EPA will investigate how grant funding may be used for such pilots. Additionally, EPA is pursuing possible ways to incorporate mobile and area source strategies into other trading and incentive programs. Through these efforts, EPA will work with States in finding solutions to adequately address concerns such as emissions variability, difficulty in controlling emissions growth, difficulty in monitoring emissions levels, and difficulty in establishing emissions baselines. Through this process, EPA and States will explore and develop the necessary protocols that could eventually allow the inclusion of mobile and area sources in some capacity in the NO_X Budget Trading Program. Anticipating that the quantification, verification, and administration concerns regarding expansion of the trading program to include mobile and area sources may be sufficiently resolved in the future, EPA is reserving in this rulemaking a section in part 96 for future inclusion of mobile or area sources in the NO_X Budget Trading Program.

The EPA is aware of other concerns on which the Agency did not receive comment, including the adequacy of some of the existing mobile source protocols and the enforcement of mobile source credit generation strategies. These emerging issues, coupled with past experience, and the issues raised by commenters lead EPA to conclude that it is not appropriate to include mobile and area sources in the NO_X Budget Trading Program at this time.

3. Monitoring

For the reasons set forth in the SNPR (63 FR 25938–40), EPA proposed that sources in the NO_X Budget Trading Program use the monitoring methodologies in proposed subpart H of part 75 to quantify their NO_X mass emissions (63 FR 28032). The comments that EPA has received can be classified into three main categories:

- Support for requiring the use of part 75 to demonstrate compliance with the trading program,
- Support for using CEMS on large units, but concerns about using part 75 as the monitoring protocol, and
- Concerns about requiring CEMS.

Some of the commenters concerned about requiring CEMS focused on units of any size that are not subject to the provisions of the Acid Rain Program. Others focused on smaller units.

The EPA proposed revisions to part 75 (63 FR 28032) for a number of reasons, one of which was to add procedures for monitoring NO_X mass emissions (subpart H). These procedures could be used by sources to comply with any State or Federal program requiring measurement and reporting of NO_X mass emissions. In particular, subpart H would be used by sources to meet the monitoring and reporting requirements of the NO_X Budget Trading Rule (part 96) and the monitoring and reporting requirements of the SIP call for (1) combustion units (boilers, turbines and combined cycle units) which serve electric generators greater than 25 MWe and (2) combustion units greater than 250 mmBtu/hr, regardless of whether they serve a generator.

The part 75 revisions also proposed to make a number of other changes that would affect units using part 75 to comply either with the requirements of title IV or the requirements of a NO_X mass emissions program that incorporated or adopted the requirements of part 75. These included a number of minor changes to simplify and streamline the rule to make it more efficient for both affected facilities and EPA, a new excepted monitoring methodology that would reduce monitoring burdens for affected facility units with low mass emissions, new quality assurance requirements based on gaps identified by EPA during evaluation of the initial implementation of part 75, and several minor technical changes to maintain uniformity within part 75 and to clarify various provisions.

The following discussion addresses comments received in the SNPR docket (A–96–56) that are related to the general requirement to monitor emissions, the requirement to monitor emissions using CEMS, and the requirement to monitor using part 75. Although EPA had requested that all comments related to the use of part 75 for monitoring NO_X mass be submitted to the part 75 docket (A–97–35), some comments also dealt with the specific requirements set forth in part 75.

In today's rulemaking, EPA is finalizing sections of part 75 related to monitoring NO_X mass emissions as well as those which address the excepted monitoring methodology for units with low mass emissions of NO_X and SO_2 that combust oil or natural gas. Units using this methodology to comply with the requirements of part 96 would be subject only to the NO_X mass emission requirements and not to the SO_2 mass emission requirements. For a more complete discussion of the NO_X mass monitoring and reporting provisions in part 75, see the Amendments to Part 75 Section below and Appendix A of this preamble. These Sections discuss both the comments received in the part 75 docket as well as the comments received in the SNPR docket that address the specific requirements of part 75.

a. Use of Part 75 to Ensure Compliance with the NO_X Budget Trading Program. Several commenters supported the idea of requiring all sources in the trading program to meet the monitoring provisions of part 75. Some of these commenters noted that part 75 provides the consistent and accurate monitoring requirements necessary to ensure the integrity of a cap and trade program. They also noted that the proposed revisions offered the flexibility needed for sources to be able to reasonably comply.

Several commenters supported the concept of trying to consolidate the monitoring and reporting requirements for units in the NO_X Budget Trading Program already subject to part 75 under the Acid Rain Program.

Response: The EPA agrees that accurate and consistent data are important to ensure the integrity of a trading program and that the protocols in part 75 provide for such accurate and consistent data from stationary combustion sources. Today's final model rule would require all sources in the trading program (including sources currently subject to part 75) to use the monitoring and reporting procedures set forth in subpart H of part 75.

b. Use of CEMS on Large Units. A number of commenters expressed support for the requirement that large units should use CEMS to quantify NO_X mass emissions. Many of these commenters did, however, have concerns about using part 75 as the basis for this monitoring. Some of these commenters elaborated that part 75 was specifically developed for utility units and that it might not be applicable to other types of units. Commenters also expressed concerns about costs associated with upgrading existing CEM systems to meet the part 75 requirements. The main alternatives they suggested were either using existing State monitoring and reporting requirements or allowing States the discretion to create or approve new monitoring and reporting requirements.

Response: For reasons set forth in the preamble to the SNPR, EPA believes that the use of CEMS, in general, and the protocols in part 75, more specifically, are the most effective way to ensure that NO_X mass emissions from large combustion sources are quantified in an accurate and consistent manner from source to source and are reported in a consistent and cost-efficient way. This is important to maintain the integrity and efficiency of the trading system.

The EPA believes that the protocols in part 75 can appropriately be applied to all of the core sources (fossil fuel-fired electric generating units and industrial boilers). The issues associated with monitoring NO_X mass emissions from a stack attached to a boiler, turbine, or combined cycle unit are the same regardless of whether that boiler, turbine, or combined cycle unit is owned or operated by a utility, by an independent power producer, or by a manufacturer. The EPA does acknowledge that there may be additional issues associated with monitoring NO_X mass from units such as process heaters or cement kilns.

The RECLAIM program uses very similar protocols to the ones in part 75 to quantify NO_X mass emissions. Both RECLAIM and part 75 require the use of NO_X CEMS and flow CEMS to quantify NO_X mass emissions from large sources combusting solid fuel. Both RECLAIM and part 75 also offer large oil and gas units an additional option for monitoring. This option involves the use of a fuel flowmeter and fuel sampling and analysis. The RECLAIM program requires monitoring of source categories that are in the NO_X Budget Trading Program core group, such as boilers and turbines, but also requires monitoring of source categories that are not in the core group, such as process heaters and cement kilns.

RECLAIM needed to establish a standing working group to resolve issues related to monitoring NO_X mass from such a wide range of source categories (See South Coast Air Quality Management District, RECLAIM Program Three Year Audit and Progress Report, May 8, 1998). EPA does not believe that the problems that RECLAIM has had with monitoring are related to the protocols that program uses. Rather, EPA believes these problems are due to the limited experience that both States and sources have with monitoring such a wide range of source categories.

The EPA believes that regardless of what protocols are used, if States opt to bring additional source categories into the trading program, issues related to monitoring at specific source categories will arise. These issues will need to be resolved, thus improving State and EPA experience with those source categories. If a State wants to include additional sources beyond those included in the core group, then EPA would resolve issues through the initial certification process for opt-in units. The EPA will also provide additional guidance on specific source categories, sharing the experiences gained with individual opt-in units.

Using one basic set of protocols will make it easier for states, sources and EPA to work together while gaining more experience with these sources and resolving the issues in a cooperative and consistent manner.

The EPA believes that the most significant costs associated with upgrading from an existing NO_X emission rate monitoring system to a part 75 NO_X mass monitoring system are associated with the need to monitor NO_X mass and would be incurred regardless of the specific monitoring protocol that was required. Many existing CEM rules other than part 75 require sources to monitor NO_X emission rate (in lbs/mmBtu) or NO_X concentration corrected for oxygen (in ppm)(e.g. monitoring requirements under Subpart D, Da, Db of part 60). In order to meet these requirements, a NO_X monitoring system must consist of a NO_X concentration CEM, a diluent CEM and a data acquisition and handling system (DAHS). The DAHS is the part of the system that collects raw monitor data, performs calculations, and generates reports.

In order to upgrade an existing system so that it can monitor NO_X mass, a source must install a flow CEMS, if it burns solid fuels, or must install either a flow CEMS or a fuel flow meter if it burns a homogeneous oil or gas. In addition, the source would have to upgrade its DAHS to reflect the reporting of NO_X mass rather than NO_X emission rate or NO_X concentration. These costs must be incurred, regardless of the protocol that a source used to monitor NO_X mass.

The EPA believes that a single monitoring and reporting protocol for the NO_X Budget Trading Program will keep the costs of upgrading systems to a minimum. This is because equipment vendors will be able to create standardized systems that will be applicable to all sources in the program, rather than having to create many different State- and source-specific systems. A single monitoring and reporting protocol will also help ensure a level playing field for all affected sources.

For these reasons, part 96 requires all large units to monitor NO_X mass emissions using CEMS in accordance with part 75. However, as explained below, part 75 does offer various monitoring options for low-emitting or infrequently operated oil- and gas-fired units, in addition to CEMS.

c. Commenters Who Do Not Believe That CEMS Are Necessary. Some commenters expressed concerns about requiring CEMS on any unit that does not currently have a CEMS monitoring requirement. Suggested alternatives included the use of stack test data and emission factors. Some commenters also suggested the testing and monitoring provisions of a source's title V permit.

Response: For large sources, EPA does not believe that stack test data and emission factors provide the consistent and accurate data needed to facilitate a trading program. Stack test data provide a one-time assessment of a source's emission rate. Emission factors at best are based on a series of stack tests at similar units. A unit's actual emission rate may fluctuate greatly over time due to factors such as the way the unit and/or its associated control equipment is operated and maintained and the quality of fuel that the unit burns. An emission factor or stack test will often not be representative of that unit's actual normal emissions. Continuous monitoring of actual emissions will ensure that fluctuations in emission rates are accounted for. Because CEMS provide continuous monitoring, they can also indicate when emission control equipment is malfunctioning, thus, helping to ensure that the owners of units continue to properly operate and maintain any installed emission control equipment.

Title V permits incorporate all of the monitoring requirements to which a source is subject in order to demonstrate compliance with its current regulatory requirements. In addition, where a source is not subject to any other monitoring requirements, it sets forth minimum monitoring requirements. In many cases the current regulatory requirements do not require compliance with a mass emissions limitation. Therefore, the monitoring requirements are not designed to demonstrate compliance with a mass emission limitation.

Even when a source may have monitoring requirements designed to demonstrate compliance with a mass emissions limitation, the stringency of these requirements often varies from source to source and from State to State. These variations in turn lead to inconsistencies in sources' accounting of mass emissions. This both creates an uneven playing field for sources and undermines the integrity of the trading program.

The EPA believes that it is necessary for all sources in the trading program to be subject to accurate and consistent monitoring requirements designed to demonstrate compliance with a mass emission limitation. This will ensure compliance with the requirements of the SIP Call and will ensure the integrity of the trading program.

The EPA does believe that it is appropriate to provide lower cost monitoring options for units with low NO_X mass emissions. Part 75 allows non-CEMS alternatives to quantify NO_X mass emissions for gas and oil fired units that have low NO_X mass emissions and/or that operate infrequently.

In contrast, EPA does not believe that the types of protocols set forth in the Compliance Assurance Monitoring (CAM) rule, part 64, are appropriate for a trading program because they were not designed to quantify mass emissions. The preamble to the CAM rule further elaborates why these protocols are not appropriate for a trading program (62 FR 54915, 54916, 54922).

The EPA believes that the types of protocols in RECLAIM and the Ozone Transport Commission's NO_X Budget Trading Program (''OTC Program'') are more appropriate for a trading program because they were specifically designed to quantify NO_X mass emissions. The EPA also believes that the flexible monitoring options offered by part 75 are consistent with the type of flexibilities offered in RECLAIM and the OTC Program. RECLAIM requires CEMS on all units that burn solid fuels and all units that emit more than 10 tons per year, regardless of the type of fuel they burn.. The OTC Program requires CEMS on all units that burn solid fuels and all units that do not qualify as peaking units, that are larger than 250 mmBtu/hr or that serve generators greater than 25 MW. Like RECLAIM and the OTC Program, part 75 requires CEMS on all units that burn solid fuel. Part 75 also requires the use of CEMS on oil and gas fired units that emit more than 50 tons of NO_X annually (or for units that only report during the ozone season, 25 tons of NO_X during the ozone season), or that don't qualify as peaking units. In both the OTC Program and part 75, a peaking unit is defined as a unit that has a capacity factor of no more than 10 percent per year averaged over a three year period and no more than 20 percent in any one year.

The EPA believes that these exceptions in part 75 provide cost-effective monitoring alternatives to CEMs for small, low mass emitting, or infrequently used units, and therefore, it is appropriate that part 96 require all units to use part 75.

d. Issues Related to Monitoring and Reporting Needed to Support a Heat Input Allocation Methodology. For monitoring and reporting NO_X mass emissions, subpart H of part 75 requires the use a NO_X concentration CEM and a flow CEM. Since the methodology does not require the use of heat input, EPA would not require sources to monitor or report heat input or NO_X emission rate for a NO_X mass emission reduction program. If a State elects to use a periodically updating allocation methodology that utilizes heat input, it may need to require sources using this methodology to monitor and report heat input also.

e. Amendments to Part 75 (1) Summary of Part 75 Rulemaking. Title IV of the CAA requires the EPA to promulgate regulations for continuous emissions monitoring (CEM). On January 11, 1993, final rules (40 CFR part 75) were published (58 FR 3590). Technical corrections were published on June 23, 1993 (58 FR 34126) and July 30, 1993 (58 FR 40746). A notice of direct final rulemaking and a notice of interim final rulemaking making further changes to the regulations were published on May 17, 1995 (60 FR 26510 and 60 FR 26560, respectively). Subsequently, on November 20, 1996, a final rule was published in response to public comments received on the direct final and interim rules (61 FR 59142).

The EPA proposed further revisions to part 75 on May 21, 1998 (63 FR 28032). These revisions included a new subpart H which sets forth procedures for monitoring NO_X mass emissions, which could be used by sources to comply with any State or Federal program requiring measurement of NO_X mass emissions, including the requirements of the NO_X Budget Trading Rule (part 96). The May 21, 1998 proposed revisions also proposed to make a number of other changes that would affect units that were using part 75 to comply either with the requirements of title IV or the requirements of a NO_X mass trading program under title I that incorporated or adopted the requirements of part 75. These included a number of minor changes to simplify and streamline the rule to make it more efficient for both affected facilities and EPA; a new excepted monitoring methodology that would reduce monitoring burdens for affected facility units with low mass emissions; and new quality assurance requirements to fill in gaps identified by EPA during evaluation of the initial implementation of Part 75.

(2) Schedule For Part 75 Final Rulemaking. The comment period for the proposed revisions to part 75 ended on July 20, 1998. EPA anticipates completing rulemaking on all of proposed revisions to part 75 by the end of the year. However, because the revisions to subpart H of part 75 relating to the monitoring and reporting of NO_X mass emissions are integral requirements of the SIP Call, EPA is finalizing most of the requirements of subpart H of part 75 with today's action.

The EPA is also finalizing a new excepted monitoring methodology for units that combust natural gas and or fuel oil with low mass emissions of NO_X and SO_2. These provisions are being finalized because they are one of the methodologies that certain gas and oil units can use to quantify NO_X mass under the new subpart H of part 75.

The EPA is not finalizing the rest of the proposed revisions to Part 75 at this time because EPA is still evaluating the comments received on the proposed rulemaking. Many of these remaining provisions will be applicable to any unit that must use the requirements of part 75 in order to meet the requirements of title IV or to meet the requirements of a State or Federal NO_X reduction program that adopts the part 75 requirements. For example, the proposed revisions would allow a unit with CEMS to be exempt from the requirement to perform a linearity test in any quarter that the combustion unit for which the CEMs is installed operates for less than 168 hours. If EPA ultimately finalizes this proposed flexibility, it will become available both to units using part 75 to comply with title IV and to units using it to comply with the part 96 model trading rule. As another example, EPA proposed quality assurance requirements for moisture monitors that would be needed if pollutant concentration (NO_X, SO_2 or CO_2) were measured on a dry basis and needed to be converted to a wet basis so that mass emissions could be determined using a stack flow meter. If EPA ultimately finalizes this proposed requirement it will affect both units using part 75 to comply with title IV and units using it to comply with part 96 (or a State or Federal NO_X mass reduction program that adopts part 75).

The EPA is also not yet finalizing the recordkeeping and reporting requirements associated with either the NO_X mass monitoring provisions in subpart H or the low mass emitter monitoring methodology because EPA believes that these reporting requirements should be coordinated with any changes in the reporting requirements that result from the finalization of the rest of proposed revisions to part 75.

Therefore, EPA has closed the part 75 docket (A–97–35, with respect to the provisions that are being finalized in today's rulemaking: section 75.19, a new excepted methodology for estimating emissions for units with low mass emissions; and subpart H, a new subpart setting forth provisions for monitoring, recording and reporting NO_X mass emissions, except where EPA has reserved final action on related aspects of these provisions. EPA has not closed the docket with respect to the other provisions that were the subject of EPA's, May 21, 1998 proposal (63 FR 28032).

(3) Summary of Major Differences Between Proposed and Final Revisions to Part 75. The final rule contains two main differences to the NO_X mass monitoring and reporting provisions from what was proposed. The first is that a new methodology for calculating NO_X mass emissions is included. This methodology utilizes a NO_X concentration CEM and a flow CEM to calculate NO_X mass emissions. The second is that sources that are not subject to title IV are not required to monitor and report data outside of the ozone season unless otherwise required to do so by the Administrator or the permitting authority administering the NO_X mass trading program.

The final rule also contains two main differences from the proposal with regard to the new excepted monitoring methodology for low mass emitters. The first is that the methodology is applicable to units with calculated NO_X mass emissions of up to 50 tons, rather than 25 tons as proposed. The second is that in lieu of using default rates for NO_X set forth in the rule, the owner or operator of a unit using this methodology may instead elect to determine a unit specific rate by conducting stack testing. All of these changes are discussed in greater detail in Appendix A of this notice. At this time EPA is only addressing the comments dealing with the two main issues for which EPA is finalizing revisions to part 75, the reporting of NO_X Mass (subpart H) and a new excepted monitoring methodology for low emitters (§ 75.19). The EPA intends to address the rest of the comments on the part 75 rulemaking in a separate, future rulemaking. The discussions in Appendix A also address comments received in the SNPR docket (A–96–56) that related specifically to the monitoring requirements set forth in part 75.

E. Emission Limitations/Allowance Allocations

Each State has the ultimate responsibility for determining the size of its trading program budget and its individual source allocations as long as the trading budget plus emissions from all other sources do not exceed the State's SIP Call budget. The proposed rule published on May 11, 1998 set timing requirements identifying when the allocations should be completed by each State and submitted to EPA for inclusion in the NO_X Allowance Tracking System (NATS) and provided an option specifying how a State might allocate NO_X allowances to the NO_X budget units. Today's final model rule clarifies the timing requirements for submission of allowance allocations to EPA and provides an optional allocation approach. Each State remains free to adopt the Model Rule's allocation approach or adopt an allocation scheme of its own provided it meets the specified timing requirements, requires new sources to hold allowances, and does not allocate more allowances than are available in the State trading budget.

1. Timing Requirements

In the SNPR, EPA set timing requirements identifying when a State would finalize NO_X allowance allocations for each control period in the NO_X Budget Trading Program and submit them to EPA for inclusion into the NATS. In developing the proposal, the Agency reasoned that uniform timing requirements would be important to ensure that all NO_X budget units in the trading program would have sufficient time and the same amount of time to plan for compliance for each control period, and sufficient time and the same amount of time to trade NO_X allowances. After considering a range of timing requirements, EPA proposed options that allocated NO_X allowances 5 to 10 years in advance of the applicable control period. The proposal attempted to strike a balance between systems that change the allocations on an annual basis and systems that establish a single, permanent allocation.

The proposed rule included the following timing requirements for the allocation of NO_X allowances: by September 30, 1999, each participating State would submit NO_X allowance allocations to EPA for the control periods in the years 2003, 2004, 2005, 2006, and 2007. After the initial allocation, two timing requirements were proposed for allocations following the year 2007. The option set forth in the proposed Model Rule would require a State to submit allocations to EPA for the control period in the year that is 5 years after the applicable submission deadline. For example, by January 1, 2003 each State participating in the trading program would issue its allocations for the control period in 2008. The State would issue allocations for the 2009 summer season by January 1, 2004. The second option, discussed in the preamble of the supplemental notice, would require the State to submit five years' worth of allowance allocations at a time, every five years, starting in 2003. For example, by January 1 , 2003, each State participating in the trading program would issue allocations for the control periods in the years 2008 through 2012. The supplemental notice solicited comment on these timing options as well as the full range of possible timing requirements (including a single, permanent allocation system and an annually changing allocation system). The supplemental notice also solicited comment on a provision requiring EPA to allocate NO_X allowances to NO_X budget units if a State were to fail to meet the timing requirements.

Comments: Although comments covered the entire range of possible timing requirements, commenters generally supported striving for administrative simplicity and ensuring sufficient planning horizons for affected sources, while still addressing the needs of a changing marketplace. Most comments fell into one of five categories.

First, a few commenters favored the option set forth in the proposed Model Rule that would update the allocations each year, five years in advance of the applicable control period. However, most of these commenters also supported a system which would update the allocations less than five years prior to the applicable control period as that would allow more recent data to be used in the allocations. One commenter advocated allocating for the previous season based on current year data (i.e., allocations would be issued at the end of the season for the preceding control period).

Approximately ten commenters favored the approach which would issue allowances five to ten years in advance. This group found that five to ten years of allocations satisfies the desire to have a sufficient planning horizon while still ensuring responsiveness to changing market conditions. Utilities generally opposed allocating single year allowances as it might be disruptive to utility planning.

The third category of commenters advocated longer term or permanent allocations. Most utility and business commenters favored allocations that were issued in ten year blocks at a minimum to provide sufficient time to plan future activities and amortize investments. A report submitted by a State proposed that allocations extend over the capital life of equipment, which was at least ten years.

A fourth set of commenters, which included three States, favored shorter term allocations. These States commented that they may want to base their allocations on more recent data than that proposed by the Model Rule and suggested that three years would provide sufficient planning time for sources. One State suggested tying allocations to the submission of triennial inventories.

A final group of commenters suggested that no timing requirement was necessary. They suggested that just as sources may participate in an interstate trading program with allocations based upon different methodologies, those same sources may participate in such a program even if they receive their allowances at different times or for different periods.

Several State commenters asserted that September 1999 was too early to have allocations set. These States suggested that the allocation process is difficult and takes longer than one year. One State suggested that the early allocation deadline would effectively prevent States from issuing allowances based upon output for the first period because an output approach could not be developed in time.

Response: Most commenters supported issuing allowances at least a couple of years prior to the season in which they would be used. The commenters generally cited the goal of balancing changing market conditions with providing sufficient planning horizons, as had the Agency in the proposal. The EPA agrees that the certainty in having allowances at least a couple of years into the future would provide some predictability for sources in their control planning and build confidence in the market. Most of the State commenters suggested three years prior to the control season as an adequate length of time for sources to know their allocations. The Agency agrees that a trading system could work with sources knowing their allocations three years prior to the control season. Therefore, EPA has modified its original proposal to ensure that sources would always have allowances at least three years in advance of the use date.

In addition to addressing how many years in advance the allocations are determined, the Agency has also considered whether allocations should be issued one control period at a time or for multiple control periods at a time (e.g., five to ten control periods). In response to the comments received, the Agency has determined that it would be appropriate to set minimum timing requirements rather than prescribing a set length of time for all States. Therefore, the Agency is now requiring States choosing to participate in the NO_X Budget Trading Program to allocate a minimum of one summer season of allowances at a time (at least three years in advance of the applicable control period).

Moving from requiring five summer seasons of allocations (three years in advance of the first season) to one summer season of allocations (three years in advance) has the advantage of allowing the allocation system to be updated sooner with more recent data. This would provide those States that want to use updating systems to more fully avail themselves of an updating system. The system could also incorporate new sources more quickly, thus reducing the need for larger new source set-asides.

However, the Agency has determined that a State may decide to issue allowances further into the future than the one-season minimum period required by this final rule and still receive streamlined EPA review of its trading program. The NO_X Allowance Tracking System will be able to handle allocations for longer periods. Therefore, this Final Rule sets out minimum timing requirements of one season (three years in advance), but States may issue allocations in larger blocks for as many as 30 seasons into the future and still receive streamlined EPA review. However, in determining the length of time for which a State issues allocations, a State should consider any potential adjustments that may occur to its future State budgets. For example, as stated in Section III.B.5.

of this preamble, the Agency may establish new budget levels for the post-2007 timeframe. States issuing long-term allocations should address how the allocations would be adjusted if new budget levels are established in the future. The Agency does believe that having allocations three years prior to the relevant control period would be the minimum needed to support an active multi-state trading market intended to reduce compliance costs for all States involved.

The three-year minimum timing requirement also is compatible with beginning the program in 2003, with at least the first year's allocations submitted to EPA by September 30, 1999. Sources will know their first year's allocations three years prior to the start of the program, and by April 1, 2003, all sources will have allocations for at least four seasons—2003, 2004, 2005 and 2006. The Agency maintains that the first year's allowances should be issued by September 30, 1999 to provide some predictability for sources in their control planning and build confidence in the market. It also ties in with the State's SIP submittal deadlines. For States participating in the trading program, the allowances are an integral part of the State's plan to satisfy the requirements of this SIP call. For sources in the Trading Program, the allowances are the mechanism by which State budget requirements are translated into source-specific limitations, and therefore the allocations should be submitted with the SIP submittals. In response to States who are worried about completing allocations in this time frame, EPA notes that one State in the OTC resolved its allocations in six weeks, demonstrating that it is possible to establish allocations in less than one year.

Requiring only one year's worth of allowances at a time has the added benefit of being able to more quickly accommodate States that want to switch allocation methodologies after the start of the program. For example, a State may decide to issue its initial allocations based on heat input data because it has not yet finalized an approach to issuing output-based allocations. The State could take a few additional years to refine the alternative approach to issuing allowances. When the State is ready to adopt the output approach, the State would be able to start using the new approach much sooner than it would be able to under a system that issued allocations in larger blocks.

Therefore, this preamble sets the following timing requirements for the allocation of NO_X allowances which will be able to accommodate States that want to issue allocations one year at a time as well as States that would like to issue allocations in larger blocks: by September 30, 1999, the State would submit NO_X allowance allocations to EPA for at least the control period of 2003. After this initial allocation, by April 1 of every year starting in 2001, the State must, at a minimum, submit allowance allocations to EPA for the control period in the year that is three years after the applicable submission deadline. For example, by April 1, 2001, a State would submit allocations for the control period in 2004. By April 1, 2002, a State would submit allocations for the control period in 2005. This minimum requirement would allow a State to submit blocks of allowances that represent any number of years should the State prefer to do so. For example, by the September 30, 1999 deadline, a State could submit allocations for only the 2003 control period or for multiple control periods (e.g., the five control periods of 2003–2007). The SIP would provide that if the State fails to submit allocations by the required date, EPA would allocate allowances based on the previous year's allocation within 60 days of the applicable deadline. This approach would ensure that starting in 2003, all sources would always have at least three years of allowances in their accounts.

Today's Model Rule presents an allocation approach that satisfies the minimum timing requirements. However, the initial allocation is for three control periods (2003–2005) because this would avoid updating allocations on an input basis. Any variation on the following approach would be acceptable providing it satisfies the minimum requirements specified in the previous paragraph. After this initial allocation, the model rule would have the State submit allowance allocations to EPA for the control period in the year that is three years after the applicable submission deadline. By April 1, 2003, a State would submit allocations for the control period in 2006. By April 1, 2004, a State would submit allocations for the control period in 2007, and so forth.

2. Options for NO_X Allowance Allocation Methodology

The Agency proposed that the NO_X Budget Trading Rule include a recommended NO_X allowance allocation methodology. The proposed Model Rule laid out an example of an allocation methodology using heat input data for source allocations. The preamble to the proposed Model Rule solicited comment on this methodology as well as two additional options using either input or output data for determining allocations. The first alternative to using heat input would base the allocation recommendation on heat input data for the first five control periods of the trading program and then convert the allocations to an output basis for the control periods after 2007. The final option would base the allocation recommendation on output data for all NO_X Budget units from the start of the trading program. The Agency also solicited comment on a suggested schedule for establishing a method for output-based allocations, and on any technical or data issues relevant to output-based allocations, as well as on the use of a fuel-neutral or output-neutral calculation to determine allocations for NO_X Budget units.

Comments: The Agency received numerous comments on the issue of whether to suggest an allocation recommendation to States. Approximately 25 commenters suggested that no recommendation is necessary. Many of these commenters emphasized that EPA had no authority to prescribe an allowance allocation methodology and a recommendation could be misinterpreted as a requirement for SIP approval. Several commenters requested that EPA clarify that the SIP approval process will be consistently applied to all States regardless of the allocation method chosen by a State, as long as the total allocation does not exceed a State's trading budget. Approximately half of the commenters who stated that no recommendation was necessary suggested that if EPA were going to make a recommendation, the recommendation should be a heat input approach.

Close to fifty commenters suggested that an Agency recommendation was a good idea, but they were divided on the appropriate methodology. This group included all the State commenters who suggested that a recommended approach was appropriate for use as a default allocation mechanism by States that did not determine their own allocations.

Many commenters supported the heat input approach used in the example in the supplemental notice. Two State commenters said that the proposed example approach was a useful default for States that did not come up with their own allocations. Other commenters suggested that heat input is an easily understood metric for all sources and the data is readily available.

However, many suggested that EPA should recommend an output method because they believe output-based allocations tend to reward more efficient fuels over fuels that require a higher heat input to generate the same amount of electricity. Other reasons cited for output-based allocations include the incentive that updating output allocations provides for reducing emissions of pollutants such as CO_2 and mercury. Several commenters suggested that output-based allocations would allow the environmental goals of the program to be achieved more cost-effectively; their arguments rested upon assertions that issuing allowances to non-NO_X emitting units in an output-based system would reduce the need for NO_X controls over time. One State commenter said that an output approach was the consensus of participants at EPA Workshops held prior to drafting of the Supplemental Notice and therefore should be the recommended approach suggested by EPA.

One commenter had a specific recommendation for an updating output-based allocation system which would issue allowances each year for the current control period. Administrative simplicity, economic efficiency, incentives for innovation, and lower consumer impact were cited as reasons supporting that position.

Additional commenters favored the output-based approach but only for fossil-fuel fired sources and renewables. Several commenters submitted letters opposing a ''fuel-neutral'' policy and objected to including nuclear sources in an output allocation to sources. They stated that a fuel neutral policy would provide incentives for nuclear generation which has the potential to release small amounts of radiation to the environment as well as the potential for generation of high-and low-level radioactive waste.

Response: As was stated in the SNPR, EPA believes that it is important for as many States as possible to participate in the NO_X Budget Trading Program. The Agency recognizes that States have unanimously favored flexibility in developing their own allocation methodologies. Further, the comments that EPA received in response to the SNPR (as well as in response to the workshops held prior to publication of the SNPR) provided no clear consensus for one methodology over another.

However, the Agency believes it is important to provide a model allocation methodology that States may choose to use as a guide for their own allocation process. Several States have commented that including an example method in the Model Rule would be useful as a backup for States who do not come up with an alternative method of allocation. An outlined approach in the Model Rule may also facilitate the regulatory process within a State that wants to quickly adopt the Model Rule.

Therefore, today's Model Rule includes an optional allocation methodology. The Agency has carefully considered arguments for alternative allocation methods. The EPA would support a decision by a State to use either heat input or output data as a basis for source allocations or for the State to auction some or all of its allocation. In determining the basis for the methodology presented in today's Model Rule, EPA has decided to use the heat input approach because it is concerned that an output-based approach has not been fully developed or made available for public comment. Further, before issuing a model output-based allocation approach, the Agency would need to make several revisions to current reporting and monitoring provisions. EPA would have to revise part 75 to monitor and report temperature, pressure, and steam heat output (mmBtu) for units with some or all of their output as heated steam. EPA would also need to put in place procedures which take advantage of the most accurate data possible. For example, the Energy Information Administration (EIA) solicited comment in a July 17, 1998 **Federal Register** Notice on a proposal to make electricity generating data non-confidential and publicly available from non-utility electricity generators (63 FR 38620). EPA will not know if this information is available to the Agency or to States through EIA for some time. If EIA were to decide that this information should remain confidential in the future, then EPA and States would need to collect their own data from sources. Additionally, the Agency is currently unaware of any public databases of output information besides those for electrical generation output for certain electrical generating units. Output information would only become available if sources report it directly to the Agency or to States.

While today's final Model Rule includes a heat input approach, the Agency is continuing to work on developing an updating output approach to source allocations. For States that wish to use output in developing their source allocations and are willing to wait for EPA to finalize such an approach, EPA plans to issue a proposed system for output-based allocations in 1999 and finalize an output-based option in 2000. However, the Agency's ability to issue an output-based approach on this schedule is contingent upon resolving the issues and promulgating the necessary rule changes mentioned in the previous paragraph.

Assuming EPA finalizes an output-based option in early 2000, States wishing to use this output-based system could adopt the necessary rules, and output data could be measured and collected at NO_X budget units during the control periods in the years 2001 and 2002. Output data could then be available for States to calculate allocations for the control periods starting in 2006. Heat-input-based allocations could be used for the 2003 through 2005 control seasons.

However, this does not prohibit a State from developing its own output-based system on a faster timeline. For example, if a State has developed an output-based approach for use in its initial allocations, it may use that approach. Or, the State may issue its initial allocation for 2003 using heat input data and then by April 1, 2001 issue output allocations for the control periods starting in 2004.

The Agency recognizes that a State's choice of when and for what blocks of time it issues allocations is intertwined with the choice of allocation methodology. Several commenters suggested that more incentives for generation efficiency and therefore ancillary environmental benefits (CO_2 and mercury reductions) are provided in an output system with periodic updates, and those incentives are lost in an heat input system that is periodically updated. These commenters suggested that with a heat-input-based system, States should issue permanent allocations rather than updating the allocations. An allocation system that issues permanent streams of allowances (using either a heat input or an output methodology) would still provide an incentive for generation efficiency although perhaps not to the extent that an updating output system might. However, if a State issues a permanent stream of allowances to existing sources, that State would have to decide how to address new sources (options include establishing an allocation set aside or an auction, or requiring new sources to obtain allowances from existing sources).

3. New Source Set-Aside

The Agency proposed an allocation set-aside account equaling 2 percent of the State trading program budget for each control period for new NO_x Budget units as part of its recommended allocation approach. The concept and size of the set-aside is included only as an optional feature of the Model Rule; however, the Model Rule requires new sources to hold allowances to cover their emissions. The supplemental notice proposed that allowances from the set-aside be given out on a first-come, first-served basis at an emission rate of 0.15 lb/mmBtu multiplied by a budget unit's maximum design heat input. The source would then be subject to a reduced utilization calculation so that a reduction in the emission rate below 0.15 lb/mmBtu would be rewarded, but a reduction in utilization would not. In other words, EPA would deduct NO_x allowances following each control period based on the unit's actual utilization for the control period. After the deduction, the allocation that had been granted to the new unit from the set-aside would equal the product of 0.15 lb/mmBtu and the budget unit's actual heat input for the season. EPA solicited comments on the use of a set-aside as part of the recommended allocation methodology as well as the proposed size and operation of the set-aside.

Comments: The Agency received many comments regarding the proposal for a new source set-aside. While several commenters were opposed to a new source set-aside because it might bias control decisions in favor of adding new sources relative to controlling existing sources, numerous other commenters expressed general support for accommodating new sources with allowances.

Several of these commenters offered suggestions for how the set-aside should be designed. A few commenters stated that the size of the set-aside should be related to the timing requirements and noted that shorter timing requirements make it easier to accommodate new growth. One commenter who advocated annually updating the allocation system noted that its proposal would eliminate the need for a new source set-aside. Some commenters supported the set-aside concept but asserted that States should be able to decide the correct size. Other commenters agreed with the set-aside concept in theory but did not think the allowances should come from existing sources.

Additional commenters had specific proposals for the size of the set-aside. One commenter suggested that the size of the set-aside should reflect the actual growth projected in budget calculations and that the unused portion of the set-aside should be retired. A few commenters agreed with the proposed 2 percent size.

Several commenters offered suggestions on how to issue the set-aside allowances to new sources. One commenter suggested that the allowances should be given to new sources at the actual emission rate if it was below the proposed 0.15 lb/mmBtu level.

Finally, several commenters suggested that the concept of a set-aside was an issue that should be left completely up to the States.

Response: The Agency believes that a new source set-aside should be large enough to provide all new units entering the trading program with allocations. The Agency maintains that as much as possible within the context of the overall trading budget, allocations should be provided to new sources on the same basis as that used for existing units until the time when the new sources receive an allocation as part of an updating allocation system. Therefore, the Agency continues to include a new source set-aside as part of its optional allocation methodology described in the Model Rule. The EPA proposed the 2 percent set-aside in the SNPR after looking at the amount of growth from new sources projected by the Integrated Planning Model (and used in the budget determinations) and estimating how much growth could be expected over the five year period that new sources might have to wait before receiving an allocation. In light of the allocation methodology and timing specified in today's Model Rule as well as revisions made to the growth factors used in State budget determinations since the SNPR, the Agency has re-evaluated the size of the new source set-aside proposal. The revised Integrated Planning Model projects approximately ½ percent annual growth in capacity utilization for new sources. Given the timing and optional allocation methodology specified in today's Model Rule, the 2003, 2004, and 2005 set-aside would need to accommodate any source that started operating after May 1, 1995. Assuming the ½ percent growth rate projected by IPM, the Agency finds that a 5 percent set-aside should be large enough to accommodate all new sources for the 2003, 2004, and 2005 control seasons.

After 2005, the new source set-aside would need to accommodate any source that commenced operation after May 1 of the control period three years prior to the control period in which the set-aside would be available. For example, in 2006, the set-aside should be large enough to accommodate any source that commenced operation after May 1, 2003. Assuming the growth rates predicted by the IPM, the Agency finds that a 2 percent set-aside should be large enough to accommodate new source growth after May 1, 2003.

A 5 percent set-aside provision for the first three control seasons and 2 percent for the control periods starting in 2006 is incorporated into today's Model Rule as an option States may adopt. However, States may choose to handle new sources in any way as long as the emissions from new sources are subject to the overall State budget. For example, some States may choose to issue allowances for longer periods of time than that outlined as the minimum requirement in today's Model Rule. These States may find that a 5 percent set-aside is not sufficient to accommodate all their new source growth, and may want to consider a larger set-aside or alternative means to accommodate new sources. Or, States may decide to allocate allowances based on a new source's permitted or actual emissions, which may be lower than 0.15 lb/mmBtu. This would require a smaller set-aside.

In the model rule set-aside provision, allowances will be issued to new sources on a first-come, first-served basis. Allowances that are not issued to new sources in the applicable control period will be returned to the existing sources in the State on a pro-rata basis to guard against the possibility of a disproportionately large set-aside.

The EPA maintains its position that new sources should receive allowances at the same rate as that applied to existing sources (i.e., large electric generating units would receive allowances at a 0.15 lb/mmBtu rate, large non-electric generating units would receive allowances at the average emission rate for existing large non-electric generating units after controls are in place, as explained in section 4 below). However, to reinforce the flexibility available on these issues, as long as a State requires new sources to hold allowances, the Agency reiterates that States may have any size set-aside (including zero), may allocate the set-aside in whatever manner they choose, and may carry over from one year to the next any amount of allowances (subject to the banking provisions on this SIP call). If a State decides to return unused allowances from a new source set-aside to existing sources, the State would indicate to EPA (as the administrator of the allowance tracking system) what number of allowances should be returned to which existing units.

4. Optional NO_X Allocation Methodology in Model Rule

While specific source allocations are required for States participating in the NO_X Budget Trading Program, the allocation methodology presented here is an optional approach that may be adopted by States. As long as a State (1) does not allocate more allowances than are available in the State NO_X trading budget, (2) requires new sources to hold allowances, and (3) issues allocations on a schedule that meets the minimum timing requirements, the State may adopt whatever methodology it finds the most appropriate and still qualify for inclusion in the NO_X Budget Trading Program.

The Model Rule contains the following optional allocation methodology. It differs from the approach presented in the proposed rule on the timing provisions, the allocation methodology for non-electric generating units, and the size of the optional new source set-aside. As proposed in the SNPR, initial unadjusted allocations to existing NO_X Budget units serving electric generators would be based on actual heat input data (in mmBtu) for the units multiplied by an emission rate of 0.15 lb/mmBtu. For the control periods in 2003, 2004, and 2005, the heat input used in the allocation calculation for large electric generating units equals the average of the heat input for the two highest control periods for the years 1995, 1996, and 1997. Once the State completes the initial allocation calculation for all the existing NO_X budget units serving electric generators for 2003, 2004, and 2005, the State would adjust the allocation for each unit upward or downward so that the total allocations match the aggregate emission levels apportioned by an approved SIP to the State's NO_X Budget units serving electric generators. Then, the State would adjust the allocation for each unit proportionately so that the total allocation equals 95 percent of the aggregate emission levels apportioned to the State's NO_X Budget units serving electric generators (to provide for the 5 percent new source set-aside). A State would submit the 2003, 2004, and 2005 allocations to EPA by September 30, 1999.

For the control periods starting in 2006, the heat input used in the allocation calculation for large electric generating units equals the heat input measured during the control period of the year that is four years before the year for which the allocations are being calculated. Once the State completes the initial allocation calculation for all existing budget units, and the State adjusts the allocations to match the aggregate emission levels apportioned to NO_X Budget units serving electric generators, the State would adjust the allocation for each unit proportionately so that the total allocation equals 98 percent of the aggregate emission levels apportioned to NO_X Budget units serving electric generators (to provide for the 2 percent new source set-aside).

For reasons explained elsewhere in today's rulemaking, EPA determined the aggregate emission levels for large non-electric generating units in each State budget based upon a 60 percent reduction rather than the 70 percent proposed in the SNPR. The 60 percent reduction results in an average emission rate across the region of 0.17 lbs/mmBtu for large non-electric generating units. Therefore, initial unadjusted allocations to existing large non-electric generating units would be based on actual heat input data (in mmBtu) for the units multiplied by an emission rate of 0.17 lb/mmBtu. For non-electric generating units subject to the trading program, 1995 heat input data is used in the allocation calculation for the control periods 2003, 2004, and 2005 (1995 is the most recent data the Agency knows is currently available for non-electric generating units). Once the State completes the initial allocation calculation for all the existing large non-electric generating units for 2003, 2004, and 2005, the State would adjust the allocation for each unit upward or downward so that the total allocations match the aggregate emission levels apportioned by an approved SIP to the State's large non-electric generating units. Then, the State would adjust the allocation for each unit proportionately so that the total allocation equals 95 percent of the aggregate emission levels apportioned to the State's large non-electric generating units (to provide for the 5% new source set-aside). A State would submit the 2003, 2004, and 2005 allocations to EPA by September 30, 1999.

For the control periods starting in 2006, the heat input used in the allocation calculation equals the heat input measured during the control period of the year that is four years before the year for which the allocations are being calculated. Once the State completes the initial allocation calculation for all existing budget units, and the State adjusts the allocations to match the aggregate emission levels apportioned to large non-electric generating units, the State would adjust the allocation for each unit proportionately so that the total allocation equals 98 percent of the aggregate emission levels apportioned to large non-electric generating units (to provide for the 2% new source set-aside).

A State would establish a separate allocation set-aside for new units each control period. Five percent of the seasonal trading budget will be held in a set-aside account for the control periods in 2003, 2004, and 2005. At the end of the relevant control period, the State would submit a NO_X allowance transfer request to EPA to return any allowances remaining in the account to the existing sources in the State on a pro-rata basis.

The allowances would be issued to new sources on a first-come first-served basis at a rate of 0.15 lb/mmBtu for NO_X Budget units serving electric generators and 0.17 lb/mmBtu for large non-electric generating units multiplied by the budget unit's maximum design heat input. Following each control period, the source would be subject to a reduced utilization calculation, in which EPA would deduct NO_X allowances based on the unit's actual utilization. Because the allocation for a new unit from the set-aside is based on maximum design heat input, this procedure adjusts the allocation by actual heat input for the control period of the allocation. This adjustment is a surrogate for the use of actual utilization in a prior baseline period which is the approach used for allocating NO_X allowances to existing units.

F. Banking Provisions

As explained in Section III.F.7., EPA requested comment in the SNPR on whether and how banking should be incorporated into the design of the NO_X Budget Trading Program. Banking may generally be defined as allowing sources that make emissions reductions beyond current requirements to save and use these excess reductions to exceed requirements in a later time period. Options ranged from a program without banking to several variations of a program with banking, prior to and/or following the start of the program. The EPA also requested comment on options for managing the use of banked allowances in order to limit the emissions variability associated with banking. The EPA specifically proposed using a ''flow control'' mechanism in cases where the potential exists for a large amount of banked allowances to be available.

This section addresses how banking has been incorporated into the NO_X Budget Trading Program based on the criteria set forth in the NO_X SIP call.

1. Banking Starting in 2003

In accordance with the provisions discussed in III.F.7.a., trading programs used to comply with the NO_X SIP call may allow banking to start in the first control period of the program, the 2003 ozone season. The majority of commenters supported banking in the context of the NO_X Budget Trading Program. Based on the advantages that banking can provide, as discussed in the SNPR and the comments, the NO_X

Budget Trading Program has been designed to allow banking starting in the first control period of the trading program. NO_X Budget units that hold additional NO_X allowances beyond what is required to demonstrate compliance for a given control period may carry-over those allowances to the next control period. These banked allowances may be used or sold for compliance in future control periods.

2. Management of Banked Allowances

The NO_X SIP call establishes that a flow control mechanism be paired with any banking provisions to limit the potential for emissions to be significantly higher than budgeted levels because of banking. This mechanism allows unlimited banking of allowances saved through emissions reductions by sources, but discourages the ''excessive use'' of banked allowances by establishing either an absolute limit on the number of banked allowances that can be used each season or a rate discounting the use of banked allowances over a given level. In the SNPR, EPA solicited comment on the application of flow control in the NO_X Budget Trading Program. Although many commenters were opposed to any restrictions on the use of banked allowances, several commenters stated that if restrictions were to be imposed, they would favor flow control as the most cost-effective, least rigid means of management. A few commenters added that, if implemented, flow control should be applied on a source-by-source basis so as to avoid penalizing all of the participants in the trading program for the excess banking of individual participants. One commenter stated that if EPA concludes that there is an adequate basis for imposing some type of restriction, it should avoid placing any absolute limit on the amount of banked allowances that can be used in a given season.

The NO_X SIP call established that flow control should be set at the 10 percent level. The effect of setting flow control at 10 percent of the trading program budget is that on a season-by-season basis, sources may use banked allowances or credits for compliance without restrictions in an amount up to 10 percent of the NO_X budget for those sources in the trading program. Banked allowances or credits that are used in an amount greater than 10 percent of the NO_X budget for those sources will have restrictions on their use.

The following provides a brief description of exactly how the flow control mechanism will operate in the NO_X Budget Trading Program. The number of banked allowances held by all participants in the multi-state trading program will be tabulated each year following the compliance certification process to determine what percentage banked allowances are of the overall multi-state trading budget for the next year. If this percentage is equal to or below 10 percent, all banked allowances may be used in the upcoming control season on a one allowance for one ton basis. If this percentage is greater than 10 percent, flow control will be triggered. In years when flow control is triggered, a withdrawal ratio will be established prior to the control period for which it would apply. The withdrawal ratio will be calculated by dividing 10 percent of the total trading program budget by the total number of banked allowances. This ratio will be applied to each compliance or overdraft account (only accounts used for compliance) holding banked allowances as of the allowance transfer deadline at the end of the control period for which it applies. Banked allowances in each account may be used for compliance on a one-for-one basis in an amount not exceeding the amount established by the withdrawal ratio. Banked allowances used in an amount exceeding that established by the withdrawal ratio must be used on a two-for-one basis. By setting the withdrawal ratio prior to the applicable control period (in years flow control is triggered) and applying it at the time of compliance certification at the end of the applicable control period, sources have one full control period to incorporate the value of using banked allowances into their operations.

As described above, the NO_X Budget Trading Program applies the flow control mechanism on a regional basis and establishes a 2-for-1 discount for banked allowances that are used in an amount greater than the flow control limit. The regional approach for applying flow control was selected over the source-by-source approach for the following reasons:

- EPA believes this option provides more flexibility to individual sources than the source-by-source approach. If the 10 percent limit were placed on each source based on the source's allocation, the limit would be in effect every year for every source, even when the amount of banked allowances throughout the entire trading region was below 10 percent of the regional trading budget. In contrast, the regional approach only applies flow control when the amount of banked allowances throughout the region (entire multi-state trading area) exceeds the 10 percent limit. In response to the commenter suggesting that the regional approach penalizes all participants in the trading program for the excess banking of individual participants, EPA notes that it would be difficult for a few sources to cause the entire regional bank to exceed 10 percent of the budget. In addition, based on the analyses presented in the RIA, EPA does not anticipate that flow control is likely to be triggered. Consequently, flow control is more of an insurance policy, rather than a provision that is routinely expected to be operational.
- The regional approach also provides flexibility to sources if and when it is triggered. Because the withdrawal ratio is set before the applicable control period but not applied until the control period's allowance transfer deadline, sources have over seven months to manage the amount of banked allowances they use on a 1-for-1 basis versus a 2-for-1 basis.
- EPA believes the regional approach is also a more universal approach than the source-by-source approach under a variety of allocation programs that States may use in the NO_X Budget Trading Program. To apply the flow control mechanism on a source-by-source basis, the 10 percent limit would be applied to each source's allocation. In this way, a source could use an amount of banked allowances up to 10 percent of it's allocation without restrictions. Restrictions would be placed on banked allowances that the source uses in an amount greater than 10 percent of its allocation. Under certain allocation programs, States may choose not to allocate NO_X allowances to new sources and require that these sources obtain the necessary amount of NO_X allowances for compliance from the market. By not having an allocation of NO_X allowances, new sources would be prevented from using banked allowances under the source-by-source approach. EPA believes that approaches to accommodate sources without a fixed allocation under the source-by-source flow control approach would overly complicate the system.
- The regional approach for applying flow control is also the approach used in the Ozone Transport Commission's (OTC) trading program. Because the NO_X Budget Trading Program is designed to include States currently operating in the OTC program, using the same approach for flow control will minimize the disruption for these sources to convert to the NO_X Budget Trading Program.

The other issue for flow control is the type of restriction to place on banked allowances used in an amount greater than the 10 percent limit. The NO_X Budget Trading Program includes the 2-for-1 discount as the applicable restriction. EPA agrees with the commenters that favored this approach over using an absolute limit. The EPA believes the 2-for-1 discount provides more flexibility for sources to achieve compliance than is offered by the absolute limit. The discount is also beneficial to the environment, when triggered, by allowing only one ton of NO_X emissions for every two tons removed. Additionally, the OTC program uses the 2-for-1 discount.

The following example illustrates how flow control will be used. For the year 2006, assume the total trading program budget across all States equals 300,000 allowances and 35,000 allowances are banked from control periods prior to the 2006 control period. Since more than 10 percent (35,000/300,000 = 11.7%) of the total trading program budget is banked, a withdrawal ratio will be established prior to the 2006 control period and will apply to all compliance and overdraft accounts (only accounts that may be used for compliance) holding banked allowances at the end of the 2006 control period. In this case, the withdrawal ratio would be 0.86 (determined by dividing 10 percent of the total trading program budget by the total number of banked allowances, or 30,000/35,000). Thus if a source holds 1,000 banked allowances at the end of the 2006 control period, it will be able to use 860 on a 1-for-1 basis, but will have to use the remaining 140, if necessary, on a 2-for-1 basis. As a result, if the source used all its banked allowances for compliance in the 2006 control period, the 1,000 banked allowances could be used to cover only 930 tons of NO_X emissions (860 + 140/2). Of course, a source could buy additional current year allowances to cover emissions on a 1-for-1 basis or buy additional banked allowances (allowances not needed by other sources for compliance) to increase the amount of banked allowances it may use on a 1-for-1 basis.

3. Early Reduction Credits

As described in section III.F.7.c., the majority of commenters generally supported the option of awarding early reduction credits. EPA is allowing, but not requiring, States to grant early reduction credits to sources for reductions in ozone season NO_X emissions prior to the 2003 ozone season. States may issue early reduction credits in an amount not exceeding the State's compliance supplement pool. The compliance supplement pool is further explained in section III.F.6.

Based on the support the commenters on the NO_X Budget Trading Program expressed for early reduction credits, EPA is including optional provisions in the trading program that States may use for issuing credits. States participating in the NO_X Budget Trading Program that choose to issue early reduction credits may follow the methodology included in part 96 or may develop their own methodology, provided the State's program meets the following requirements. The State program must ensure that early reduction credits will not be issued in an amount exceeding the State's compliance supplement pool. The State program must also meet the criteria for early reduction credits discussed in section III.F.7.c. Finally, the State should notify EPA of the amount of credits issued to particular NO_X Budget units by no later than May 1, 2003. Early reduction credits shall be issued to units as allowances for the 2003 control period. For purposes of the banking provisions, the allowances will not be considered banked in the 2003 control period. However, any unused allowances carried from the 2003 control period to the 2004 control period shall be considered banked as will be the case for all unused allowances carried over to the next control period. Per the requirements discussed in section III.F.7.c., allowances issued for early reduction credits may be used for compliance by sources in the 2003 and 2004 control periods. Any of these allowances that are not used for compliance in the 2003 or 2004 control periods shall be retired by EPA from the account in which they are held.

As discussed in Section III.F.6.b.ii., States also have the option of issuing some or all of the State's compliance supplement pool directly to sources according to the criteria for direct distribution. Consequently, States participating in the NO_X Budget Trading Program may also use the direct distribution option for issuing the compliance supplement pool. In this case, the State must notify EPA by May 1, 2003 of the specific NO_X Budget units that will be receiving the direct distribution.

4. Optional Methodology for Issuing Early Reduction Credits

The methodology described below is an optional methodology included in part 96 that States participating in the NO_X budget Trading Program and choosing to issue early reduction credits may follow. States participating in the NO_X Budget Trading Program may also choose to develop their own methodology as discussed above. The following methodology is designed to meet the criteria for issuing early reduction credits discussed in section III.F.7.c. and to provide incentives for a State's NO_X budget units to generate early credits in an amount no greater than the size of the State's compliance supplement pool. The State may choose to issue the entire compliance supplement pool as early reduction credits through this methodology, or the State may choose to reserve some of the compliance supplement pool to be issued to sources according to the direct distribution criteria as described above.

This methodology is applicable for reductions made during the 2001 and 2002 ozone seasons. NO_X budget units that request early reduction credits will be required to monitor ozone season NO_X emissions according to the monitoring provisions of part 75, subpart H by the 2000 ozone season. The information from the 2000 ozone season shall be used to establish a baseline emission rate for the NO_X budget unit. To be eligible for early reduction credits, a NO_X budget unit shall reduce its emissions rate in the 2001 and/or 2002 control period(s) no less than 20 percent below its baseline emissions rate established for the 2000 ozone season. The size of the early reduction credit request shall equal the difference between 0.25 lb/mmBtu and the unit's actual emissions rate multiplied by the unit's actual heat input for the applicable control period. NO_X Budget units requesting early reduction credits should submit the request to the State by no later than October 30 of the year for which the early reductions were generated.

The methodology conforms with the NO_X SIP call's criteria for early reduction credits. By requiring that the reductions be measured using provisions in part 75, the reductions will be verified as having actually occurred and will be quantified according to the same procedures as required for compliance with the general requirements of the NO_X Budget Trading Program. The procedure for calculating the credit request is intended to ensure that the reductions are surplus. Phase II of the title IV NO_X emissions limits are required to be installed at specific coal-fired boilers by January 1, 2000. By requiring that an early reduction credit must be generated by no less than a 20 percent reduction below the 2000 baseline emission rate, credits will only be issued for reductions that go below emissions levels achieved for compliance with title IV requirements. This provision ensures that the early reduction credits are only issued for reductions below existing requirements (i.e., surplus).

Calculating the early credit based on the difference between 0.25 lb/mmBtu and the unit's actual emissions rate establishes a standard emissions rate from which all early reduction credits are calculated. This approach ensures that sources with higher NO_X emissions rates prior to the 2001 ozone season are not provided an opportunity to generate more early reduction credits than relatively cleaner sources. In this way, all sources have an equal opportunity to generate early reduction credits below a standard emissions rate.

According to the requirements in the NO_X SIP call, States may not issue early reduction credits in an amount greater than the State's compliance supplement pool. To ensure this provision is met, the optional methodology is designed for States to issue all early reduction credits following the 2002 ozone season. By October 30, 2002, a State will have received all early reduction requests for both the 2001 and 2002 ozone seasons. After review of the requests, the State would issue credit to all valid requests according to the following procedure. If the amount of valid requests is less than the size of the State's compliance supplement pool, the State would issue one allowance for each ton of early reduction credit requested. If the amount of valid requests is more than the size of the State's pool, the State would reduce the amount in the credit requests on a pro-rata basis so that the requests equal the size of the State's pool. After the requests have been reduced, the State would then issue allowances based on the remaining size of each credit request. States would complete the issuance of allowances for the early reduction credit requests as soon as possible following October 30, 2002, but no later than May 1, 2003.

5. Integrating the OTC Program With the NO_X Budget Trading Program's Banking Provisions

The OTC NO_X Budget Program is a multi-state, capped NO_X trading program that begins in 1999 and includes many States subject to today's action. By the start of the NO_X Budget Trading Program under the NO_X SIP call, sources in the OTC program will potentially hold banked NO_X allowances resulting from early reductions and/or overcontrol with program requirements. At issue is the ability of OTC sources to use these banked allowances in the NO_X Budget Trading Program.

Commenters have supported allowing OTC sources to use banked allowances (i.e., early reductions from the 1997 and 1998 ozone seasons and unused allowances from the 1999 through 2002 ozone seasons) from the OTC program for compliance in the NO_X Budget Trading Program. Commenters have stated that because OTC sources will be subject to a market-based cap-and-trade program prior to the 2003 ozone season, it is important to create a smooth transition from the OTC program to the NO_X Budget Trading Program. They have suggested discounting OTC Phase II allowances to make them equivalent to those achieved under the NO_X SIP call. One OTC State suggested accomplishing this by adjusting the OTC banked allowances by a ratio of the Phase II OTC control requirement to the Phase III OTC control requirement, working with EPA to determine the exact ratio. A few OTC States suggested that OTC allowances banked in Phase II could be used as early reduction credits in the NO_X Budget Trading Program. A commenter from outside the OTC voiced concern that the use of OTC allowances banked by sources for the years 1999 through 2002 could distort the larger trading market established under the SIP call.

The EPA believes that the compliance supplement pool provides the opportunity to integrate the OTC program into the NO_X Budget Trading Program by allowing OTC States to bring their banked allowances into the NO_X Budget Trading Program as early reduction credits after the 2002 ozone season. The EPA established two primary criteria for the generation of early reduction credits in III.F.7.c.: first, the credits must be surplus, verifiable, and quantifiable; and second, a State may not grant an amount of early reduction credits in excess of a State's compliance supplement pool. EPA believes that banked allowances held by sources in the OTC program would qualify as being surplus, verifiable, and quantifiable. The banked allowances would be surplus because they would represent emissions reductions that go beyond what is required by the emissions limitations established by the OTC program in the applicable ozone seasons. The banked allowances would also be verified and quantified according to the procedures in the OTC program which are essentially identical to the requirements that will be in place under the NO_X Budget Trading Program.

As for the second criterion that a State issue no more early reduction credits than provided through the compliance supplement pool, EPA believes this could be addressed according to the following procedure. If the number of banked allowances held by an OTC State's NO_X Budget units, after the compliance certification process for the 2002 ozone season, is less than the number of credits available in the pool for that State, the NO_X budget units in that State may carry all of their banked allowances from the OTC program into the NO_X Budget Trading Program. The banked allowances brought in from the OTC program would be subtracted from the State's compliance supplement pool. Any remaining credits in the compliance supplement pool could be distributed by the OTC State through the direct distribution option, if necessary. If, on the other hand, an OTC State's NO_X Budget units hold banked allowances from the OTC program in excess of the amount of credits in the State's pool, after the compliance certification process for the 2002 ozone season, the State would need to reduce the amount of allowances eligible for being carried into the NO_X Budget Trading Program. This could be achieved by reducing the amount of banked allowances held by the units on a pro rata basis so that the number of allowances carried into the NO_X Budget Trading Program is less than or equal to the size of the State's compliance supplement pool.

The process described above provides a mechanism for OTC States to use the compliance supplement pool to carry banked allowances from the OTC program as of the end of the compliance period in 2002 over into the NO_X Budget Trading Program. The EPA believes this integration acknowledges the important reductions made in the OTC program prior to 2003 while providing similar opportunities for sources outside the OTC to generate credits for early reductions. Since all States in the NO_X Budget Trading Program will have an opportunity to receive credit for early reductions, EPA does not believe any market distortion will occur.

G. New Source Review

Under the New Source Review (NSR) provisions of section 173 of the CAA, a new major source or a major modification to an existing major source of a particular pollutant that proposes to locate in an area designated nonattainment for that pollutant must offset its new emissions. In the SNPR, the EPA solicited comment on whether and how the offset requirement could be met by sources' participation in the NO_X Budget Trading Program. The Agency stated its belief that sources obligated to obtain NO_X offsets under the NSR program should be able to do so by acquiring NO_X allowances through the trading program. In essence, the EPA reasoned that, where a trading program is a capped system, a new source's acquisition of allowances to cover its increased emissions would necessarily result in actual emissions reductions elsewhere in the system.

The EPA continues to believe that nonattainment NSR offset requirements of the CAA can be met using the mechanism of the NO_X Budget Trading Program. However, there are a number of complex issues involved with integrating these programs, for example, the statutory requirements to obtain offsets from certain geographic areas and, depending on the classification of the 1-hour ozone nonattainment area, at certain offset ratios. Because the Agency is continuing to evaluate these issues, it will not be providing guidance at this time on integrating these programs; however, the EPA intends to provide such guidance as soon as possible. At that time, the EPA will respond to the comments received on this topic in the course of this rulemaking.

VIII. Interaction With Title IV NO_X Rule

The EPA proposed, in the May 11, 1998 supplemental notice, to add a new § 76.16 to part 76, the Acid Rain NO_X Emission Reduction Program regulations. The purpose of the proposed § 76.16 was to increase utilities' flexibility in situations where units owned or operated by a utility were subject to both a NO_X cap-and-trade program and the Phase II NO_X emission limitations under the Acid Rain NO_X Emission Reduction Program. Under proposed § 76.16, a State or group of States could request that the Administrator relieve all units located in the State or States and otherwise subject to the Phase II NO_X emission limitations (under §§ 76.6 and 76.7) of the requirement to comply with such emission limitations. The Administrator could also take this action on his or her own motion. All Group 1 boilers (i.e., tangentially fired or dry bottom wall fired boilers) would remain subject to the Phase I NO_X emission limitations (under § 76.5), while Group 2 boilers (i.e., cell burner boilers, cyclones, wet bottom boilers, and vertically fired boilers) would have no NO_X limits under the Acid Rain Program. This relief would be available if all such units were subject, under a SIP or a FIP, to a NO_X cap-and-trade program meeting certain requirements. The NO_X cap-and-trade program had to include, *inter alia,* either an annual cap or seasonal caps that together limited total annual emissions and a requirement that each unit use authorizations to emit (or allowances) to account for all NO_X emissions. In addition, there had to be a demonstration that total annual NO_X emissions from all units otherwise subject to the Acid Rain NO_X emission limitations and located in the State or group of States would, under the NO_X cap-and-trade program, be equal to or lower than the total number of annual NO_X emissions if the units remained subject to the Acid Rain NO_X emission limitations. Alternative emission limitations and NO_X averaging plans under part 76 would not be taken into account in such a demonstration.

Although the purpose of proposed § 76.16 was to provide more flexibility to utilities consistent with the requirements of section 407, almost all utility commenters and many State and State agency commenters opposed the proposal. Many commenters argued that relieving a utility's units in one State of the applicability of the Phase II NO_X emission limitation would prevent the utility from using those units, along with units that the utility owns or operates in other States, in an interstate averaging plan under the Acid Rain Nitrogen Oxides Emission Reduction Program. Under section 407(e) of the CAA, as implemented under § 76.11, a utility may comply with the Acid Rain NO_X emission limitations by averaging the emissions of units that the utility owns or operates in the same State or other States. Many utilities have complied, or plan to comply, with the Acid Rain NO_X Emission Reduction Program by using averaging plans, including some interstate averaging plans. However, a unit that has no Acid Rain emission limitation obviously cannot be included in an averaging plan since EPA would have no authority under title IV to limit the unit's emissions, whether on an individual-unit or a group-average basis. Further, as a practical matter, the group average limit for any given year, which must be calculated based on the limit applicable to each individual unit in the averaging plan, could not reflect any limit for such a unit. *See* 40 CFR 76.11(a) (1) and (2) (allowing only units with Acid Rain NO_X emission limitations in effect to participate in an averaging plan) and (d)(1)(ii)(A) (showing calculation of the group average limit using each unit's Acid Rain NO_X emission limitation).

In the proposal, EPA attempted to address the issue of the potential impact of proposed § 76.16 on averaging plans. Proposed § 76.16(b)(1)(ii) required that, in determining whether a NO_X cap-and-trade program met the requirements for granting units relief from the Phase II NO_X emission limitations, the Administrator must consider ''whether the cost savings from trading will be offset by elimination of the ability of an owner or operator of a unit in the State or the group of States to use a NO_X averaging plan under § 76.11.'' 63 FR 25974. However, commenters were still concerned that the Administrator could, even after taking this into consideration, grant the relief over a utility's objections and prevent the utility from using an averaging plan that included the units for which the Administrator made the Phase II NO_X emission limitations inapplicable. In light of the utilities' concerns that proposed § 76.16 would actually reduce utilities' compliance flexibility, albeit under title IV, and prevent the use of averaging plans authorized under section 407(e), EPA has decided *not* to revise part 76 as proposed and is *not* adopting proposed § 76.16 as a final rule.

Suggestions by some commenters that, instead of adopting proposed § 76.16, EPA extend the compliance date under the Acid Rain Program for the Phase II NO_X emission limitations are rejected as outside the scope of this rulemaking. As acknowledged by commenters, that issue was raised in the rulemaking adopting the Phase II NO_X emission limitations, and the compliance deadline of January 1, 2000 set in that rulemaking was recently upheld by the courts in *Appalachian Power* v. *EPA,* 135 F.3d 791 (D.C. Cir. 1998). The SIP call rulemaking did not include any proposal to alter that date. On the contrary, EPA stated in the SIP call:

Obviously, in proposing a new 40 CFR 76.16, EPA is not requesting comment on any aspect of the December 19, 1996 final rule [i.e., the rule that set the Phase II NO_X emission limitations and that included an earlier, proposed version of § 76.16], including any issues addressed by the Court in *Appalachian Power.* 63 FR 25951.

Similarly, commenters' suggestions concerning other revisions to the Acid Rain NO_X Emission Reduction Program regulations (e.g., revisions to change the averaging provisions in the Acid Rain regulations to allow averaging among units that lack common owners or operators) are rejected as outside the scope of this rulemaking.

IX. Non-Ozone Benefits of NO_X Emissions Decreases

A. Summary of Comments

One commenter suggested that drinking water nitrate is not affected by atmospheric emissions and that the impacts of eutrophication are unknown, although no evidence was presented. Another commenter stated that EPA should estimate in the RIA the benefits of the SIP call with respect to the non-ozone impacts. One comment was received stating that EPA should not consider non-ozone benefits as justification for the proposed emission reductions.

B. Response to Comments and Conclusion

1. Drinking Water Nitrate

There is no disagreement that high levels of nitrate in drinking water is a health hazard, especially for infants. The contribution of atmospheric nitrogen (N) deposition to elevated levels of nitrate in drinking water supplies can be described as an evolving impact area. The Ecological Society of America has included discussion of this impact in a recent major review of causes and consequences of human alteration of the global N cycle in its Issues in Ecology series (Vitousek, Peter M., John Aber, Robert W. Howarth, Gene E. Likens, et al. 1997. Human Alteration of the Global Nitrogen Cycle: Causes and Consequences. Issues in Ecology. Published by Ecological Society of America, Number 1, Spring 1997). For decades, N concentrations in major rivers and drinking water supplies have been monitored in the United States, Europe, and other developed regions of the world. Analysis of these data confirms a substantial rise of N levels in surface waters, which are highly correlated with human-generated inputs of N to their watersheds. These N inputs are dominated by fertilizers and atmospheric deposition.

Increases in atmospheric N deposition to sensitive forested watersheds approaching N saturation would be expected to result in increased nitrate concentrations in stream water. This phenomenon has been documented in the Los Angeles, California area and has been well-established for areas in Germany and the Netherlands (Riggan, P.J., R.N. Lockwood, and E.N. Lopez, ''Deposition and Processing of Airborne Nitrogen Pollutants in Mediterranean-Type Ecosystems of Southern California'' Environmental Science and Technology, vol. 19, 1985). Stream water nitrate concentrations in watersheds subject to chronic air pollution in the Los Angeles area were two to three orders of magnitude greater than in chaparral regions outside the air basin.

2. Eutrophication

The EPA believes that the eutrophication problem associated with atmospheric nitrogen deposition is well established. The National Research Council recently identified eutrophication as the most serious pollution problem facing the estuarine waters of the United States (NRC, 1993). NO_X emissions contribute directly to the widespread accelerated eutrophication of United States coastal waters and estuaries. Atmospheric nitrogen deposition onto surface waters and deposition to watershed and subsequent transport into the tidal waters has been documented to contribute from 12 to 44 percent of the total nitrogen loadings to United States coastal water bodies. Nitrogen is the nutrient limiting growth of algae in most coastal waters and estuaries. Thus, addition of nitrogen results in accelerated algae and aquatic plant growth causing adverse ecological effects and economic impacts that range from nuisance algal blooms to oxygen depletion and fish kills.

3. Regulatory Impact Analysis

The EPA believes it is important to note the potential impacts of the rulemaking, including the substantial benefits to the environment of several non-ozone impacts. As described in the November 7 proposal, in addition to contributing to attainment of the ozone NAAQS, decreases of NO_X emissions will also likely help improve the environment in several important ways: (1) On a national scale, decreases in NO_X emissions will also decrease acid deposition, nitrates in drinking water, excessive nitrogen loadings to aquatic and terrestrial ecosystems, and ambient concentrations of nitrogen dioxide, particulate matter and toxics; and (2), on a global scale, decreases in NO_X emissions will, to some degree, reduce greenhouse gases and stratospheric ozone depletion. These benefits were also specifically recognized by OTAG, which in its July 8, 1997 final recommendations, stated that it ''recognizes that NO_X controls for ozone reductions purposes have collateral public health and environmental benefits, including reductions in acid deposition, eutrophication, nitrification, fine particle pollution, and regional haze.'' However, the benefits of some of these impacts are very difficult to estimate. Where possible, EPA provides estimates of the impacts of the rulemaking—both ozone and non-ozone—in the RIA.

4. Justification for Rulemaking

While EPA believes this information is important for the public to understand and, thus, needs to be described as part of the rulemaking and RIA, there should be no misunderstanding as to the legal basis for the rulemaking, which is described in Section I, Background, of this notice and does not depend on the non-ozone benefits. The non-ozone benefits did not affect the method in which EPA determined significant contribution nor the calculation of the emissions budgets.

X. Administrative Requirements

A. Executive Order 12866: Regulatory Impacts Analysis

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

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

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

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

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

In view of its important policy implications and potential effect on the economy of over $100 million, this action has been judged to be a ''significant regulatory action'' within the meaning of the Executive Order. As a result, the final rulemaking was submitted to OMB for review, and EPA has prepared a Regulatory Impact Analysis (RIA) entitled ''Regulatory Impact Analysis for the Regional NO_X SIP Call (September 1998).''

This RIA assesses the costs, benefits, and economic impacts associated with potential State implementation strategies for complying with this rulemaking. Any written comments from OMB to EPA and any written EPA response to those comments are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** Section of this preamble. The RIA is available in hard copy by contacting the EPA Library at the address under ''Availability of Related Information'' and in electronic form as discussed above under ''Availability of Related Information.''

The RIA attempts to simulate a possible set of State implementation strategies and estimates the costs and benefits associated with that set of strategies. The RIA concludes that the national annual cost of possible State actions to comply with the SIP call are approximately $1.7 billion (1990 dollars). The associated benefits, in terms of improvements in health, crop yields, visibility, and ecosystem protection, that EPA has quantified and monetized range from $1.1 billion to $4.2 billion. Due to practical analytical limitations, the EPA is not able to quantify and/or monetize all potential benefits of this action.

B. Regulatory Flexibility Act: Small Entity Impacts

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. No. 104–121) (SBREFA), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. *See, Motor and Equip. Mfrs. Ass'n* v. *Nichols,* 142 F.3d 449 (D.C. Cir. 1998); *United Distribution Cos.* v. *FERC,* 88 F.3d 1105, 1170 (D.C. Cir. 1996); *Mid-Tex Elec. Co-op, Inc.* v. *FERC,* 773 F.2d 327, 342 (D.C. Cir. 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

The NO_X SIP Call would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit SIP revisions that would achieve the necessary NO_X emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose which sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could not predict the effect of the rule on small entities.

For these reasons, EPA appropriately certified that the rule would not have a significant impact on a substantial number of small entities. Accordingly, the Agency did not prepare an initial RFA for the proposed rule.

For the final rule, EPA is confirming its initial certification. However, the Agency did conduct a more general analysis of the potential impact on small entities of possible State implementation strategies. This analysis is documented in the RIA. The EPA did receive comments regarding the impact on small entities. These comments will be addressed in the Response to Comment document.

This final rule will not have a significant impact on a substantial number of small entities because the rule does not establish requirements applicable to small entities. Therefore, I certify that this action will not have a significant impact on a substantial number of small entities.

C. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) (UMRA), establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, 2 U.S.C. 1532, EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that ''includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more * * * in any one year.'' A ''Federal mandate'' is defined under section 421(6), 2 U.S.C. 658(6), to include a ''Federal intergovernmental mandate'' and a ''Federal private sector mandate.'' A ''Federal intergovernmental mandate,'' in turn, is defined to include a regulation that ''would impose an enforceable duty upon State, local, or tribal governments,'' section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is ''a condition of Federal assistance,'' section 421(5)(A)(i)(I). A ''Federal private sector mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector,'' with certain exceptions, section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under section 202 of the UMRA, section 205, 2 U.S.C. 1535, of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule.

The EPA has prepared a written statement consistent with the requirements of section 202 of the UMRA and placed that statement in the docket for this rulemaking. Furthermore, as EPA stated in the proposal, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Furthermore, as described in the proposal, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA and Executive Order 12875, EPA carried out consultations with the governmental entities affected by this rule. Finally, the written statement placed in the docket also contains a discussion consistent with the requirements of section 205 of the UMRA.

For several reasons, however, EPA is not reaching a final conclusion as to the applicability of the requirements of UMRA to this rulemaking action. First, it is questionable whether a requirement to submit a SIP revision would constitute a federal mandate in any case. The obligation for a state to revise its SIP that arises out of sections 110(a) and 110(k)(5) of the CAA is not legally enforceable by a court of law, and at most is a condition for continued receipt of highway funds. Therefore, it is possible to view an action requiring such a submittal as not creating any enforceable duty within the meaning of section 421(5)(9a)(I) of UMRA (2 U.S.C. 658 (a)(I)). Even if it did, the duty could be viewed as falling within the exception for a condition of Federal assistance under section 421(5)(a)(i)(I) of UMRA (2 U.S.C. 658(5)(a)(i)(I)).

As noted earlier, however, notwithstanding these issues EPA has prepared the statement that would be required by UMRA if its statutory provisions applied and has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements. The analysis assumes that states would adopt the control strategies that EPA assumed in its analyses underlying this action. The EPA further notes that in two related proposals also signed today—one concerning federal implementation plans if States do not comply with the SIP call and one concerning the petitions submitted to the Agency under section 126 of the CAA—EPA is taking the position that the requirements of UMRA apply because both of those actions could result in the establishment of enforceable mandates directly applicable to sources (including sources owned by state and local governments).

D. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of

Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 1857.02) and a copy may be obtained from Sandy Farmer by mail at Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M St., SW., Washington, DC 20460, by email at farmer.sandy@epa.gov, or by calling (202) 260–2740. A copy may also be downloaded from the internet at http://www.epa.gov/icr. The information requirements are not effective until OMB approves them.

The EPA believes that it is essential that compliance with the regional control strategy be verified. Tracking emissions is the principal mechanism to ensure compliance with the budget and to assure the downwind affected States and EPA that the ozone transport problem is being mitigated. If tracking and periodic reports indicate that a State is not implementing all of its NO_X control measures beginning with the compliance date for NO_X controls or is off track to meet its statewide budget by September 30, 2007, EPA will work with the State to determine the reasons for noncompliance and what course of remedial action is needed.

The reporting requirements are mandatory and the legal authority for the reporting requirements resides in section 110(a) and 301(a) of the CAA. Emissions data being requested in today's rule is not be considered confidential by EPA. Certain process data may be identified as sensitive by a State and are then treated as ''State-sensitive'' by EPA.

The reporting and record keeping burden for this collection of information is described below:

Respondents/Affected Entities: States, along with the District of Columbia, which are included in the NO_X SIP call.

Number of Respondents: 23.

Frequency of Response: annually, triennially.

Estimated Annual Hour Burden per Respondent: 269.

Estimated Annual Cost per Respondent: $7,140.00.

Estimated Total Annual Hour Burden: 6,197.

Estimated Total Annualized Cost: $164,190.00.

There are no additional capital or operating and maintenance costs for the States, along with the District of Columbia, associated with the reporting requirements of this rule. During the 1980s, an EPA initiative established electronic communication with each State environmental agency. This included a computer terminal for any States needing one in order to communicate with the EPA's national data base systems. Costs associated with replacing and maintaining these terminals, as well as storage of data files, have been accounted for in the ICR for the existing annual inventory reporting requirements (OMB # 2060–0088).

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Office of Policy, Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M St., SW.; Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th St., NW., Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Comments are requested by November 27, 1998. Include the ICR number in any correspondence.

E. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

1. Applicability of E.O. 13045

The Executive Order 13045 applies to any rule that EPA determines (1) ''economically significant'' as defined under Executive Order 12866, and (2) the environmental health or safety risk addressed by the rule has a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children; and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This proposed rule is not subject to E.O. 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), because it does not involve decisions on environmental health risks or safety risks that may disproportionately affect children.

2. Children's Health Protection

In accordance with section 5(501), the Agency has evaluated the environmental health or safety effects of the rule on children, and found that the rule does not separately address any age groups. However, the Agency has conducted a general analysis of the potential changes in ozone and particulate matter levels experienced by children as a result of the NO_X SIP call; these findings are presented in the Regulatory Impact Analysis. The findings include population-weighted exposure characterizations for projected 2007 ozone and PM concentrations. The population includes a census-derived subdivision for the under 18 group.

F. Executive Order 12898: Environmental Justice

Executive Order 12898 requires that each Federal agency make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minorities and low-income populations. The Agency has conducted a general analysis of the potential changes in ozone and particulate matter levels that may be experienced by minority and low-income populations as a result of the NO_X SIP call; these findings are presented in the Regulatory Impact Analysis. The findings include population-weighted exposure characterizations for projected ozone concentrations and PM concentrations. The population includes census-derived subdivisions for whites and non-whites, and for low-income groups.

G. Executive Order 12875: Enhancing the Intergovernmental Partnerships

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and that creates a mandate upon a State, local or tribal government, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by those governments. If the mandate is unfunded, EPA must provide to the Office of Management and Budget a description of the extent of EPA's prior consultation with representatives of affected State, local and tribal governments, the nature of their concerns, copies of any written communications from the governments, and a statement supporting the need to issue the regulation. In addition, Executive Order 12875 requires EPA to develop an effective process permitting elected officials and other representatives of State, local and tribal governments ''to provide meaningful and timely input in the development of regulatory proposals containing significant unfunded mandates.''

Today's rule does not create a mandate on State, local or tribal governments. As explained in the discussion of UMRA (Section X.C), this rule does not impose an enforceable duty on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 do not apply to this rule.

H. Executive Order 13084: Consultation and Coordination With Indian Tribal Governments

Under Executive Order 13084, EPA may not issue a regulation that is not required by statute, that significantly or uniquely affects the communities of Indian tribal governments, and that imposes substantial direct compliance costs on those communities, unless the government provides the funds necessary to pay the direct compliance costs incurred by the tribal governments. If the mandate is unfunded, EPA must provide to the Office of Management and Budget, in a separately identified section of the preamble to the rule, a description of the extent of EPA's prior consultation with representatives of affected tribal governments, a summary of the nature of their concerns, and a statement supporting the need to issue the regulation. In addition, Executive Order 13084 requires EPA to develop an effective process permitting elected and other representatives of Indian tribal governments ''to provide meaningful and timely input in the development of regulatory policies on matters that significantly or uniquely affect their communities.''

Today's rule does not significantly or uniquely affect the communities of Indian tribal governments. The rule applies only to certain States, and does not require Indian tribal governments to take any action. Moreover, EPA does not, by today's rule, call on States to regulate NO_X sources located on tribal lands. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

The only circumstance in which the rule might even indirectly affect sources on tribal lands would be if the budget set for one or more of the 23 jurisdictions reflects assumed emissions reductions from NO_X sources on tribal lands located within the exterior boundaries of those States. The EPA is not aware of any such sources. However, to address the possibility that one or more of the State budgets reflects reductions from such sources, and because any such State generally would not have jurisdiction over such sources (see EPA's rule promulgated under CAA section 301(d), 63 FR 7254, February 12, 1998), EPA will consider any request to revise as appropriate the budget and base year 2007 emissions inventory for such a State, based on a demonstration that the State does not have authority to regulate those sources.

I. Judicial Review

Section 307(b)(1) of the CAA indicates which Federal Courts of Appeal have venue for petitions of review of final actions by EPA. This Section provides, in part, that petitions for review must be filed in the Court of Appeals for the District of Columbia Circuit if (i) the agency action consists of ''nationally applicable regulations promulgated, or final action taken, by the Administrator,'' or (ii) such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.''

Any final action related to the NO_X SIP call is ''nationally applicable'' within the meaning of section 307(b)(1). As an initial matter, through this rule, EPA interprets section 110 of the CAA in a way that could affect future actions regulating the transport of pollutants. In addition, the NO_X SIP call, as proposed, would require 22 States and the District of Columbia to decrease emissions of NO_X. The NO_X SIP call also is based on a common core of factual findings and analyses concerning the transport of ozone and its precursors between the different States subject to the NO_X SIP call. Finally, EPA has established uniform approvability criteria that would be applied to all States subject to the NO_X SIP call. For these reasons, the Administrator also is determining that any final action regarding the NO_X SIP call is of nationwide scope and effect for purposes of section 307(b)(1). Thus, any petitions for review of final actions regarding the NO_X SIP call must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

J. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A ''major rule'' cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. § 804(2). This rule will be effective December 28, 1998.

K. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Pub. L. No. 104–113, section 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rulemaking sets forth a model trading program including environmental monitoring and measurement provisions that States are encouraged to adopt as part of their SIPs. If States adopt those provisions, sources that participate in the trading program would be required to meet the applicable monitoring requirements of part 75. In addition, this final rulemaking requires States that choose to regulate certain large stationary sources to meet the requirements of the SIP call to use part 75 to ensure compliance with their regulations. Part 75 already incorporates a number of voluntary consensus standards. In addition, EPA's proposed revisions to part 75 proposed to add two more voluntary consensus standards to the rule (see 63 FR at 28116–17, discussing ASTM D5373–93 ''Standard Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in laboratory samples of Coal and Coke,'' and API Section 2 ''Conventional Pipe Provers'' from Chapter 4 of the Manual for Petroleum Measurement Standards, October 1988 edition). The EPA's proposed revisions to part 75 also requested comments on the inclusion of additional voluntary consensus standards. The EPA is finalizing some revisions to part 75 now, including the incorporation of two voluntary consensus standards, in response to comments submitted on the proposed part 75 rulemaking:

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19 and,

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed October 1992), for § 75.19.

These materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070.

These standards are used to quantify fuel use from units that have low emissions of NO_X and SO_X.

The EPA intends to finalize other revisions to part 75 in the near future and address comments related to the proposed voluntary consensus standards and to additional voluntary consensus standards at that time.

Consistent with the Agency's Performance Based Measurement System, part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. The EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified, however any alternative methods must be approved in advance before they may be used under part 75.

List of Subjects

40 CFR Part 51

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

40 CFR Parts 72 and 75

Air pollution control, Carbon dioxide, Continuous emissions monitors, Electric utilities, Environmental protection, Incorporation by reference, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 96

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

Dated: September 24, 1998.

Carol M. Browner,

Administrator.

Appendix A to the Preamble—Detailed Discussion of Changes to Part 75

The following discussion addresses the comments received both on the SNPR (68 FR 25902) and the proposed part 75 revisions (68 FR 28032) that relate to the monitoring of NO_X mass emissions. In addition, it addresses the comments received on the excepted monitoring methodology for low mass emitting units that would apply to both units affected by title IV of the CAA and to units affected by a State or Federal NO_X mass reduction program that adopted or incorporated the requirements of this part.

I. NO_X Mass Monitoring and Reporting Provisions

Commenters raised four main issues with the proposed NO_X mass monitoring and reporting provisions in subpart H. The first issue has to do with the appropriate monitoring requirements necessary to support a NO_X mass monitoring program, particularly in light of the fact that many of the units that would be subject to a program based on Part 96 are not currently monitoring NO_X mass emissions. The second has to do with using a NO_X concentration CEMS and a flow CEMS to calculate NO_X mass. The third has to do with the requirement to report NO_X mass emissions year round even though the ozone season is only 5 months long. The final issue has to do with the requirement to have petitions for alternatives to part 75 be approved by both the state permitting authority and by EPA.

A. Background on Use of Part 75 to Monitor and Report NO_X Mass Emissions

Subpart H of the proposed part 75 rule set forth general monitoring and reporting requirements that sources subject to a State or Federal NO_X mass emission reduction program could incorporate or adopt into that program. Several commenters argued that it was inappropriate to require sources, who were not already required to meet the requirements of part 75, to meet those requirements for purposes of a state program.

Commenters who suggested that it was inappropriate to require a source that is not already subject to part 75 to meet the requirements of part 75 for purposes of a state program suggested that the State should decide what requirements the source needs to meet. The EPA agrees that this would be appropriate in the case of a program that only affected that state. For instance, if a State was developing a NO_X reduction program to address its own non-attainment problem, it would not be necessary to adopt requirements that were consistent across a larger geographic area. However, in a multi-state program, particularly a multi-state trading program which engages in interstate commerce like the one set forth in part 96, EPA believes it is necessary to account for emissions in a consistent manner across the whole region. This ensures that all sources that participate in the trading program account for their emissions in a consistent manner, ensuring both integrity in the trading program and a level playing field for all program participants. Therefore, EPA believes that it is necessary to create one set of consistent monitoring and reporting requirements that can be used for such a program. This is consistent with the way the Act mandated that a multi-state trading program be implemented under Title IV. It is also consistent with the approach taken in implementing other emissions standards, such as the new source performance standards that affect many states. This approach also makes it easier for states designing their programs since they would not have to reinvent the monitoring requirements in each case.

Commenters who suggested that part 75 did not provide enough flexibility focused on three areas: they suggested that other programs such as RECLAIM or the OTC trading program provided more flexible non-CEMS options for units that operated infrequently or had low NO_X mass emissions; they suggested that sources should be allowed to use predictive emissions monitoring systems (PEMS); and they suggested that sources should be allowed to use coal sampling and weighting to determine heat input.

The EPA believes that the flexibilities offered by part 75 are consistent with the type of flexibilities offered in RECLAIM and the OTC Program. RECLAIM requires CEMS on all units that emit more than 10 tons of any individual pollutant per year. The OTC Program requires CEMS on all units that do not qualify as peaking units that are larger than 250 mmBtu or serve generators greater than 25 MWs. Subpart H of part 75 allows non-CEMS alternatives for units that have emissions less than 50 tons per year of NO_X. If a unit is not required to report SO_2 and CO_2 for Acid Rain compliance, then the unit may use the low mass emissions provisions of Part 75 if its NO_X emissions are less than 50 tons per year. Part 75 also allows non-CEMS alternatives for units that qualify as peaking units. In both the OTC Program and part 75, a peaking unit is defined as a unit that has a capacity factor of no more than 10 percent per year averaged over a three year period and no more than 20 percent in any one year. The EPA believes that these options provide cost effective monitoring methodologies for small or infrequently used units.

While commenters who supported the use of PEMS and the use of coal sampling and weighting asserted that these methodologies would provide data equivalent to that provided by the methodologies in Part 75, none of the commenters provided any data to justify this claim. Therefore EPA is not adding specific requirements that would allow either of these methodologies. It should be noted that subpart E of part 75 does provide a means for a source to demonstrate that an alternative methodology such as PEMS or coal sampling and weighting is equivalent to CEMS. Subpart E of part 75 is consistent with Performance Based Measurement Systems criteria. Any source wishing to use an alterative methodology may petition the agency under subpart E of part 75.

B. Background on Use of a NO_X Concentration CEMS and a Flow CEMS to Calculate NO_X Mass

Subpart H of the proposed part 75 rule called for sources in the NO_X Budget Program to monitor NO_X emission rate in lb/mmBtu using a NO_X concentration monitor and a diluent monitor, and then to multiply this by heat input, calculated using a flow monitor and a diluent monitor. Under this proposal, sources would then calculate NO_X mass emissions by multiplying the hourly NO_X emission rate by the hourly heat input to obtain the pounds of NO_X emitted during the hour. The EPA also requested comment on whether it would be appropriate for sources in the NO_X Budget Program to use the NO_X concentration monitor and flow monitor without a diluent monitor to calculate NO_X mass emissions. This is analogous to the Acid Rain Program's current approach to monitoring SO_2 mass emissions.

Commenters recommended that the Agency require sources to determine NO_X mass emissions from pollutant concentration and stack gas volumetric flow. The commenters stated that this approach would be more accurate, more familiar to sources, and more consistent with the SO_2 mass emissions monitoring in the existing part 75.

The Agency agrees that using NO_X pollutant concentration and volumetric flow is an appropriate method for monitoring NO_X mass emissions. Today's final rule includes provisions in Subpart H and Section 8 of Appendix F of part 75 to allow sources to choose one of several options for monitoring and calculating NO_X mass emissions. Sources may monitor NO_X mass emissions by using either:

All Units

- A NO_X pollutant concentration monitor and a volumetric flow monitor, or a NO_X concentration monitor and a diluent monitor to calculate NO_X emission rate in lb/mmBtu, and a flow monitor and a diluent monitor to calculate heat input; or
- A NO_X concentration monitor and a diluent monitor to calculate NO_X emission rate in lb/mmBtu, and a fuel flow meter and oil or gas sampling and analysis to calculate heat input; or

Oil/Natural Gas Fired Units

- Peaking units may use NO_X to load correlation procedures from Appendix E of part 75 for NO_X emission rate, and a fuel flow meter and oil or gas sampling and analysis to calculate heat input; or
- Units with less than 50 tons of Nox and 25 tons of SO_2 may use emission rates multiplied by either the maximum rated heat input capacity of the unit or by the actual heat input of the unit which may be determined on a longer term basis than a single hour.

The EPA decided to allow sources several options so that they could use monitoring equipment that is already installed under part 75 to the greatest extent possible.

In implementing these options, a source would need to designate a primary approach to calculating NO_X mass emissions. For example, the designated representative of a coal-fired unit could choose to designate a primary monitoring approach under Option 1 (pollutant concentration monitor and diluent monitor, and diluent monitor and flow monitor). The designated representative could then use a (pollutant concentration monitor and flow monitor) as a backup monitoring approach. This would be useful for periods when the diluent monitor is not operating properly, where NO_X emission rate data in lb/mmBtu would not be available, but NO_X mass emission data in lb could still be available. The OTC NO_X Budget Program allows this approach (see docket A–97–35 item II-I–7).

In order to make monitoring as consistent as possible between the first two approaches for monitoring NO_X mass emissions using continuous emission monitoring systems (CEMS), EPA is making additional changes to part 75. First, the Agency is adding language in Section 8 of Appendix F that specifies the calculations for NO_X mass emissions using either approach. Second, EPA is requiring sources that use a NO_X pollutant concentration monitor and a flow monitor as the primary method for calculating NO_X mass emissions to substitute for missing NO_X pollutant concentration data using the same missing data procedures as for NO_X CEMS (lb/mmBtu) under §§ 75.31(c), 75.33(c) and Appendix C. Third, the Agency is establishing a relative accuracy testing requirement for NO_X pollutant concentration monitors that are used to calculate NO_X mass emissions independently of a NO_X CEMS (lb/mmBtu). The NO_X pollutant concentration monitors will need to meet a relative accuracy of 10.0 percent to pass the relative accuracy test audit (RATA). They will need to meet a relative accuracy of 7.5 percent to perform a RATA on an annual basis instead of a semi-annual basis. Because the vast majority of NO_X CEMS (lb/

mmBtu) and SO_2 pollutant concentration monitors routinely meet a relative accuracy of 7.5 percent or less, the Agency concludes that it will also be possible for a NO_X pollutant concentration monitor, which is part of a NO_X CEMS, to meet this standard. Fourth, EPA requires these sources to test their NO_X pollutant concentration monitor and flow monitor for bias. If the monitor is found to be biased low, then the source must either fix the monitor and retest it to show it is not biased, or apply a bias adjustment factor to hourly data. These changes to part 75 make monitoring consistent between the different monitoring approaches using CEMS, prevent underestimation of emissions, preserve monitoring accuracy, and take advantage of approaches already developed for other monitoring systems that will be familiar to sources.

The EPA decided to allow sources to calculate NO_X mass emissions using NO_X concentration and flow rate for several reasons:

- This approach would allow sources to remove bias due to the diluent monitor from calculations of NO_X mass emissions.
- Sources affected by the NO_X Budget Program, but not by the Acid Rain Program, such as industrial boilers, may be able to simplify their recordkeeping and reporting because they will not need to calculate or report NO_X emission rate in lb/mmBtu for each hour for the trading program.
- Sources will be able to maintain higher availability of quality-assured NO_X mass emission data, because they will not need to substitute missing data for purposes of NO_X mass emissions when data are not available from the diluent monitor.
- As the commenters suggested, this approach is more analogous to monitoring for SO_2 mass emissions in the Acid Rain Program.

Because this approach is already allowed under the OTC NO_X Budget Program, EPA already has accounted for this possibility in the electronic data reporting format and in its computerized Emission Tracking System.

For these reasons, the Agency believes that it is appropriate to allow sources the option of monitoring and calculating NO_X mass emissions using NO_X pollutant concentration and flow monitors.

Sources using this approach may still be required to install maintain and operate a diluent monitor to calculate heat input if required to do so by their state for purposes of obtaining data needed to support allocation of NO_X allowances.

C. Background on Year Round Reporting of NO_X Mass Emissions

The proposal would have required all units to report NO_X mass emissions on an annual basis rather than on an ozone season basis. One commenter noted that since the proposed SIP call would not require emission reductions outside of the ozone season it is not necessary to report NO_X mass emissions outside of the ozone season. The EPA agrees that solely for the purposes of an ozone program, it may not be necessary to report NO_X mass emissions outside of the ozone season except if a source wants to qualify for the low mass emissions provision. However the requirements of subpart H could be used to support NO_X mass emission reduction programs where reductions would be required annually. In addition, the monitoring and reporting requirements could be used to help consolidate other State or Federal reporting that would be required on an annual basis. Therefore in the final rule the requirements of subpart H have been modified so that they no longer require annual reporting of NO_X mass emissions, but rather defer to the State or Federal rule that is incorporating these requirements to define the applicable time period for reporting.

In addition a new section has been added to subpart H that details how the requirements of part 75, which are designed to be used annually, should be used if monitoring and reporting is being done for only part of the year.

Some of the most significant differences include:

- Owners and operators of units using the fuel sampling procedures in Appendix D must ensure that they have accurate fuel sampling information at the beginning of the ozone season. This requires either sampling the fuel tank itself before the start of the ozone season or meeting the requirements to sample fuel deliveries on a year round basis.
- Historical lookback periods for missing data periods only need to include data from the ozone season. However, if a monitor is out of control at the beginning of the season, historical data from seven months ago may represent significantly different operating conditions (e.g. fuel burned or use of control equipment). Therefore the AAR would have to certify that the operating conditions are representative of the previous years operating conditions. If the conditions are not representative, the standard missing data procedures could not be used. In this case maximum potential NO_X mass emissions would have to be substituted.
- The owner or operator of a unit must ensure that the monitors used for monitoring and reporting are in control. Since CEMS require ongoing quality assurance to ensure that they are operating properly, owners and operators of units that do not meet this requirement during the non-ozone season will have to recertify their monitors before the start of the ozone season.

D. Background on Requiring EPA and the State Permitting Authority to Approve Alternatives to Part 75

The proposal would have required owners and operators of units that are not subject to the requirements of title IV of the CAA that wish to petition for an alternative to any of the requirements of part 75 to petition both the state permitting authority and the Administrator. Several commenters suggested that approval of one or the other should suffice. Some of the commenters also noted that the requirements were different for units affected by title IV, who are only required to petition the Administrator.

The EPA agrees that the requirements for units affected by title IV and units not affected by title IV are inconsistent. Because of different requirements of the Act this inconsistency is necessary. The EPA has the sole authority to grant petitions to units affected by title IV under § 75.66 of part 75. If a State incorporates those monitoring requirements into its State rules, this still does not give it the authority to change or waive the monitoring requirements for a unit subject to title IV. However, recognizing that granting a petition affects the accounting of NO_X mass emissions for a State program, EPA does intend to work cooperatively with State agencies on petition requests that could affect monitoring and reporting of NO_X mass emissions.

For sources not affected by title IV that are complying with the requirements of subpart H because they have been adopted or incorporated into a State SIP, neither EPA nor the State has sole authority to approve a petition for an alternative. While the State does have the authority to set forth specific monitoring and reporting requirements in a SIP and submit those requirements for EPA approval, a State does not have the discretion to modify the SIP by changing or waiving those monitoring and reporting requirements without obtaining EPA approval. Likewise, EPA does not have sole authority to revise a SIP since the primary responsibility to develop and implement a SIP is granted to the States under the CAA. The EPA is however required by the CAA to review and approve or disapprove SIP revisions. Since a petition to change or waive unspecified requirements related to monitoring and reporting can not be approved as part of the original SIP approval process, EPA must be involved in any approvals of alternatives to the SIP.

In addition to the title I requirements for EPA to be involved in approval of petitions for alternatives to part 75, there are several other reasons that EPA needs to be involved. The first is that since EPA is administering the emissions data collection system under part 75, EPA must ensure that any changes to the reporting requirements can be handled by the emissions tracking system that EPA maintains. Secondly, in order to ensure the integrity of a multi-state market based system and to ensure that participants in the system are treated equitably, it is important to ensure that sources are treated equitably from State to State. Therefore, if interstate trading is taking place EPA clearly has a role in approving petitions for alternatives to ensure that sources are treated consistently from state to state when engaging in such interstate commerce.

II. Low Mass Emissions Excepted Monitoring Methodology

A. Background

In the January 11, 1993 Acid Rain permitting rule, EPA provided for a conditional exemption from the emissions reduction, permitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions (see 58 FR 3593–94 and 3645–46). Moreover, in the January 11, 1993 monitoring rule, EPA allowed gas-fired and oil-fired peaking units to use the provisions of Appendix E, instead of CEMS, to determine the NO_X emission rate, stating that this was a *de minimis* exception. The EPA allowed this exception from the requirements of section 412 of the CAA because the NO_X emissions from these units would be extremely low, both collectively and individually (see 58 FR 3644–45). One utility wrote to the Agency, suggesting that the Agency consider further regulatory relief for other units with extremely low emissions that do not fall under the categories of small new units burning fuels with a sulfur content less than or equal to 0.05 percent by weight or gas-fired and oil-fired peaking units (see Docket A–97–35, Item II–D–31). The utility specifically suggested that the Agency consider an exemption, the ability to use Appendix E, or some other simplified methods which are more cost effective.

In the process of implementing part 75, other utilities also have suggested to EPA that it provide regulatory relief to low mass emitting units (see Docket A–97–35, Items II–D–29, II–E–25). These units might be low mass emitting because they use a clean fuel, such as natural gas, and/or because they operate relatively infrequently. Some utilities stated that they spend a great deal of time reviewing the emissions data when preparing quarterly reports for these units. Others argued that it would be important to reduce monitoring and quality assurance (QA) requirements in order to save time and money currently devoted to units with minimal emissions (see Docket A–97–35, Item II–E–25).

In response to the requests for simplified monitoring and recordkeeping requirements for units which both operate infrequently and have low mass emissions on May 21, 1998 the Agency proposed, under § 75.19 of part 75, changes to the monitoring requirements that would allow a new excepted methodology for low mass emission units. The proposed low mass emissions methodology would have allowed units which have emissions less than 25 tons of both NO_X and SO_2 to use a methodology with reduced monitoring, reporting and quality assurance requirements than the use of CEMS or either appendix D or E methodologies. The methodology proposed used a unit's maximum rated hourly heat input and generic defaults for SO_2, NO_X and CO_2 mass emissions. The proposed methodology was a less accurate methodology for determining emissions for SO_2, NO_X and CO_2 but would significantly reduce the burden on industry for these sources. The allowance of this methodology was justified using the *de minimis* individual and aggregate emissions represented by the units who would qualify for the methodology.

While the proposed methodology did not contain an explicit cutoff for CO_2, EPA believes that the limited applicability of the proposal ensured that emissions of CO_2 from units that would qualify to use the proposal was also *de minimis*. This is important, because under section 821 of the Act, the agency is also required to collect CO_2 emissions data from sources subject to title IV. This data is required to be collected ''in the same manner and to the same extent'' as required under title IV.

The Agency solicited comments on both the proposed methodology for determining emissions and the proposed applicability limits of 25 tons for both NO_X and SO_2 as well as any other comments related to the proposed low mass emission methodology. In reviewing the comments submitted on the proposal, the Agency noted that several commenters suggested the methodology was too restrictive and would only allow reduced monitoring to a limited number of units. The commenters suggested various methods for expanding applicability to the low mass emission methodology the most common which are; (i) remove the requirement for units to have both SO_2 and NO_X emissions of less than 25 tons and instead to allow units to use the methodology on a pollutant specific basis; (ii) increase the 25 ton limit for NO_X and SO_2 to 50, 100 or 250 tons; (iii) allow additional methods for calculating heat input; and (iv) allow the use of unit-specific NO_X emission rates. One other significant comment was received which indicated that the default values for NO_X emission rate in table 1b of proposed § 75.19 (c) could significantly underestimate emissions from certain types of units.

In response to the comments, which generally advocating the applicability of the low mass emissions methodology to more units, the Agency is adopting the proposed low mass emissions methodology with the following changes: (1) the NO_X applicability limit is being raised to 50 tons which will increase the number of units that can use the methodology; (2) units are being allowed an optional procedure for heat input which will increase the number of units that can use the methodology and provide more accurate emission estimates; (3) units are being allowed to use unit-specific NO_X emission rates determined through testing which will allow increased applicability and more accurate emissions estimates for NO_X; and (4) the values for NO_X emission rate in table 1b of proposed 75.19 (c) are being changed to prevent underestimation of emissions using the methodology.

B. Discussion of Low Mass Emissions Methodology

Today's new Low Mass Emissions methodology incorporates optional reduced monitoring, quality assurance, and reporting requirements into part 75 for units that burn only natural gas or fuel oil, emit no more than 25 tons of SO_2 and no more than 50 tons of NO_X annually, and have calculated annual

SO_2 and NO_X emissions that do not exceed such limits. Units that are not subject to Title IV of the Act and that are only subject to subpart H of part 75 are not required to meet the SO_2 limit to qualify to use the methodology. In addition, if allowed by their State, they may qualify as low mass emission units during the ozone season if they emit less than 25 tons of NO_X per ozone season.

A unit may initially qualify for the reduced requirements by demonstrating to the Administrator's satisfaction that the unit meets the applicability criteria in § 75.19(a). Section 75.19(a) requires facilities to submit historical actual (or projections, as described below) and calculated emissions data from the previous three calendar years demonstrating that a unit falls below the 25-ton cutoff for SO_2 and the 50 ton cutoff for NO_X. The calculated SO_2 mass emissions data for the previous three calendar years will be determined by choosing one of the two heat input options in § 75.19(c) and the appropriate emission rate from table 1a in § 75.19(c). The calculated NO_X mass emissions data for the previous three calendar years will be determined by choosing one of the two heat input options in § 75.19(c) and either the appropriate emission rate from table 1b in § 75.19(c) or a unit-specific NO_X emission rate as allowed under § 75.19(c). The data demonstrating that a unit meets the applicability requirements of § 75.19(a) will be submitted in a certification application for approval by the Administrator to use the low mass emissions excepted methodology.

For units that lack historical data for one or more of the previous three calendar years (including new units that lack any historical data), § 75.19(a) will require the facility to provide (1) any historical emissions and operating data, beginning with the unit's first calendar year of commercial operation, that demonstrates that the unit falls under the 25-ton cutoffs for SO_2 and the 50 ton cutoff for NO_X, both with actual emissions and with calculated emissions using the proposed methodology, as described below; and (2) a demonstration satisfactory to the Administrator that the unit will continue to emit below the tonnage cutoffs (e.g., for a new unit, applying the applicable emission rates and applicable hourly heat input, under § 75.19(c), to a projection of annual operation and fuel usage to determine the projected mass emissions).

For units with historical actual (or projections, as described above) emissions and calculated emissions falling below the tonnage cutoffs, facilities allowed to use the optional methodology in § 75.19(c) in lieu of either CEMS or, where applicable, in lieu of the excepted methods under Appendix D, E, or G for the purpose of determining and reporting heat input, NO_X emission rate, and NO_X, SO_2, and CO_2 mass emissions. The facility will no longer be required to keep monitoring equipment installed on low mass emissions units, nor will it be required to meet the quality assurance test requirements or QA/QC program requirements of Appendix B to part 75. Moreover, emissions reporting requirements will be reduced by requiring only that the facility report the unit's hourly mass emissions of SO_2, CO_2, and NO_X, the fuel type(s) burned for each hour of operation, and report the quarterly total and year-to-date cumulative mass emissions, heat input, and operating time, in addition to the unit's quarterly average and year-to-date average NO_X emission rate for each quarter. Owners and operators may also choose to report partial hour operating time and use the operating time to obtain a more accurate estimate of heat input determined using the maximum hourly heat input option. For units which use the optional long term fuel flow methodology for heat input the source will report hourly and cumulative quarterly and yearly output in either megawatts electrical output or thousands of pounds of steam. For units which use unit-specific NO_X emission rates determined through testing, reporting of the Part 75 Appendix E test results will be required. For units that have NO_X controls, data demonstrating that these controls are operating properly will have to be kept on site. Facilities will continue to be required to monitor, record, and report opacity data for oil-fired units, as specified under §§ 75.14(a), 75.57(f), and 75.64(a)(iii) respectively. Under § 75.14(c) and (d), however, gas-fired, diesel-fired, and dual-fuel reciprocating engine units will continue to be exempt from opacity monitoring requirements.

If an initially qualified unit subsequently burns fuel other than natural gas or fuel oil, the unit will be disqualified from using the reduced requirements starting the first date on which the fuel (other than natural gas or fuel oil) burned.

In addition, if an initially qualified unit subsequently exceeds the 25-ton cutoff for either SO_2 or the 50 ton cutoff for NO_X while using the adopted methodology, the facility will no longer be allowed to use the reduced requirements in § 75.19(c) for determining the affected unit's heat input, NO_X emission rate, or SO_2, CO_2, and NO_X mass emissions (unless at a future time the unit can again meet the applicability requirements based on the recent three years of data). Adopted § 75.19(b) allows the facility two quarters from the end of the quarter in which the exceedance of the relevant ton cutoff(s) occurred to install, certify, and report SO_2, CO_2, and NO_X data from a monitoring system that meets the requirements of §§ 75.11, 75.12, and 75.13, respectively.

Under the low mass emission excepted methodologies in § 75.19(c), a facility will calculate and report hourly SO_2, NO_X and CO_2 mass emissions by multiplying hourly unit heat input by an appropriate emission rate. Unit heat input is determined using one of two heat input methodologies, maximum rated hourly heat input or long term fuel flow; unit SO_2 and CO_2 emission rates are determined using generic defaults; and unit NO_X emission rate is determined using one of two methodologies, generic defaults or unit-specific NO_X emission rate testing.

Commenters raised three major issues, which have led EPA to modify its proposal. The three major issues raised were: (i) Should the proposed initial and ongoing applicability criteria of 25 tons of both NO_X and SO_2 be modified; (ii) was the proposed methodology for estimating emissions appropriate and, should other options for calculating emissions be allowed; and (iii) what should the reduced monitoring and quality assurance requirements be for these units?

1. Applicability Criteria

a. Approach. Based on the rationale described in the preamble to the May 12, 1998 proposal (63 FR 28037) and in the absence of significant adverse comment, the Agency is using both actual and calculated emissions as the basis for determining initial applicability.

b. Cutoff Limit for Applicability. Several commenters requested that the cutoff limit for applicability of the low mass emission provision be increased. These comments fell into two broad categories: (1) decouple the NO_X and SO_2 requirements and allow units which qualify as a low mass emissions unit for only one pollutant to monitor that pollutant using the low mass emissions methodology (see Docket A–97–35, Items, IV–D–24, IV–D–11, IV–D–23, IV–G–03, IV–D–20); and (2) raise the tonnage cutoff for NO_X and SO_2 (see Docket A–97–35, Items, IV–G–03, IV–D–24, IV–D–22, IV–D–23, IV–D–07, IV–G–02).

c. Determining the Criteria for Low Mass Emitters. Based on comments received the Agency believes that the low mass emission provision is appropriate for units which have low mass emissions because: (i) a unit has a low capacity factor usage or operates infrequently; or (ii) a unit has low mass emissions despite a relatively high capacity factor due to the small size of the unit. For these units, the cost of installing and maintaining CEMS would represent a relatively large portion of the total value of the electricity or steam produced by the unit. The Agency, also reasoned that the types of units identified above can use the excepted methodology without any significant risk to the environment or impairment of the Agency's ability to meet its obligations under the CAA.

The Agency also determined the types of units which were not appropriate candidates for use of the low mass emissions excepted methodology. In particular, the Agency has concerns about allowing large numbers of controlled units to use an estimation methodology such as the low mass emission methodology. Because many of these units have low mass emissions not because they operate infrequently, but rather because they have controls which reduce their emission rates, their continued low mass emissions is dependent on continued proper operation of the controls on the unit. The EPA believes that monitoring actual emission rates is necessary to ensure that installed emission controls are operating properly and that actual emissions remain low. On the other hand, EPA believes that it is appropriate to allow small or infrequently operated units with controls, such as peaking turbines with water or fuel injection, to use the low mass emissions provision. This is appropriate because as long as these units continue to limit their operation, their potential to emit still remains low, even if their controls are not working. Therefore, while EPA believes it is appropriate to allow small infrequently operated units with controls that have both low actual emissions and a low potential to emit (as long as they continue to operate at low levels), EPA does not believe that it is appropriate to allow controlled units that have large potential to emit if their controls are not operating properly to use this methodology.

The low mass emission excepted methodology is a new exception, in addition to the exceptions in the existing rule, from the requirement for a NO_X CEMS. The determination of whether individual and collective emissions covered by the exceptions from CEMS are *de minimis* must include consideration of emissions from both new and existing units that will qualify to use the new low mass emissions excepted methodology and also new and existing units that will qualify to use other exceptions from the NO_X CEM requirement, i.e. units using the existing appendix E excepted methodology and units with new unit exemptions under § 72.7.

The EPA has first considered the level of projected aggregate emissions determined to be *de minimis* for purposes of developing the new unit exemption promulgated in the January 11, 1993 Acid Rain permitting rule (58 FR 3593–94 and 3645–46). Aggregate emissions projected for units under the exemption were approximately 138 cumulative tons of SO_2 and 1934 cumulative tons of NO_X emitted per year from an estimated 170 new units which might qualify for the exception before the year 2000. As of September of 1998, 278 exemptions have actually been granted under the new unit exemption. The Agency estimates that the level of SO_2 and NO_X mass emissions from these units is 226 tons of NO_X and 3163 tons of SO_2. The Agency further believes that this group of excepted units will continue to increase at the current rate.

The EPA has also considered the level of emissions projected to be covered by appendix E. The EPA, in the January 11, 1993 Acid Rain monitoring rule, allowed gas-fired and oil-fired peaking units to use the provisions of appendix E, instead of CEMS, to determine the NO_X emission rate. The Agency stated that, even though this method was less accurate than CEMS, this was a *de minimis* exception because emissions from all units that qualify to use the appendix E reporting methodology were projected to be extremely low, the units did not have a NO_X compliance obligation, and the cost of installing and operating CEMS for these units would be high (see 58 FR 3644–45). The preamble to the January 11, 1993 rule estimated the emissions from oil and gas units which operated with a capacity factor of less than 10 percent to be 40,000 tons of NO_X per year. The Agency has analyzed existing appendix E units to determine the actual NO_X mass emissions reported by these units in 1997. This analysis indicates that in 1997 approximately 235 units used the appendix E methodology and had total emissions of approximately 11,000 tons of NO_X in 1997. (see Docket A–97–35, Items, IV–A–1).

The Agency has then considered what level of total NO_X emissions would be *de minimis* for all units that may be covered by *de minimis* exceptions from the requirement to use CEMS i.e. all units using the new unit exemption, appendix E, and the new low mass emissions methodology. The Agency maintains that a *de minimis* level of total NO_X emissions should not be more than one percent of the total NO_X emission inventory currently or in the future for all units. This approach is supported by the treatment of 40,000 tons of NO_X as *de minimis* in the January 11, 1993 rule preamble concerning appendix E, which is somewhat less than 1 percent of the total NO_X emissions estimated for 1993. However, the 40,000 tons of NO_X determined to be *de minimis* emissions in 1993 is not an appropriate *de minimis* level with regard to current and future levels of NO_X emissions. Several factors have increased the importance of monitoring lower levels of NO_X emissions including: (i) The new more stringent NAAQS for ozone (NO_X is an ozone precursor); (ii) title IV Phase II NO_X reductions which will reduce the total NO_X inventory; (iii) today's NO_X SIP call which may result in NO_X compliance obligations for gas-and oil-fired units and will reduce the NO_X emission inventory; and (iv) State and regional NO_X reduction programs, such as the OTC program, State RACT rules and the RECLAIM program in California, which result in NO_X compliance obligations for gas-and oil-fired units and reduced NO_X emission inventory. As a result, EPA views about 20,000 tons (close to 1 percent of projected NO_X emission inventory) as the *de minimis* level of NO_X emissions for the present and foreseeable future. Given that appendix E units and new unit exemption units currently account for about 14,100 tons of NO_X there is not a large margin left for establishing additional exception to the CEM requirements. The Agency has considered potential future growth in the number of units using the new unit exemption or appendix E in order to estimate what level of additional NO_X, SO_2 and CO_2 emissions might be appropriate to allow under the low mass emissions methodology. Taking account of the uncertainty inherent in such estimates EPA has set the applicability criteria for the low mass emission methodology so that the NO_X emissions covered by the methodology plus future growth in NO_X emissions covered by the other current *de minimis* exceptions (appendix E and the new unit exemption) will not exceed 5000 tons of NO_X per year in the future.

The Agency has analyzed SO_2, NO_X and CO_2 emissions and determined that, as long as the cutoffs for NO_X and SO_2 are coupled so that a unit must meet both the 50 tons of NO_X and 25 tons of

SO_2 limits, that SO_2, NO_X and CO_2 emissions under all exceptions from CEMS requirements will remain *de minimus*. Additionally decoupling the NO_X and SO_2 tons would allow only marginal simplification in monitoring while significantly complicating the low mass emissions methodology.

d. Determining the Tonnage Cutoffs for SO_2 and NO_X. The Agency has conducted a study of actual emissions data from 1997 quarterly reports under part 75 and evaluated potential tonnage cutoffs for SO_X and NO_X (see Docket A–97–35, Item IV–A–1). The analysis was based on the assumption that reported 1997 emissions of NO_X and SO_2 will be more representative of calculated emissions under the final low mass emissions methodology than they would have been under the proposed methodology. The assumption is considered valid because the final low mass emissions methodology allows more accurate heat input determination using long term fuel flow and the use of fuel and unit specific NO_X emission rates. These options allow more accurate emissions estimates than the proposed methodology would have. This differs from the analysis performed for the proposed low mass emission methodology which calculated emissions based on operating hours and maximum rated heat input.

Based on this analysis, EPA estimates that the existing Acid Rain affected sources that would qualify for the low mass emissions excepted methodology using a coupled 50 tons NO_X and 25 tons SO_2 limit would represent aggregate emissions of approximately 3100 tons of NO_X and approximately 260 tons of SO_2 in 1997 from 224 units. The analysis indicates that the applicability has been substantially increased in response to the comments received.

For the proposed 25 ton NO_X cutoff , which is the limiting factor for applicability in nearly all instances, the Agency has considered increasing the tons of NO_X to 50 tons, 75 tons, 100 tons, and 250 tons as suggested by various commenters. In its analysis, the Agency kept SO_2 at 25 tons, as discussed above.

The analysis showed that by increasing the NO_X limit to 250 tons coupled to 25 tons of SO_2, the aggregate tons of NO_X and SO_2 emitted by units which could currently qualify for the low mass emissions methodology increased to approximately 23124 tons NO_X and 4503 tons of SO_2; this is without considering potential future growth in the number of units that could qualify to use this exemption. Increasing the cutoff for NO_X to 250 tons could also allow many units with highly effective NO_X controls to use the low mass emissions provision. As explained previously, units with effective NO_X controls and high operating capacity should not use the low mass emission provision. The EPA concludes that with a 250 ton NO_X mass emissions applicability cutoff, the aggregate NO_X tons and percentage of inventory potentially covered by all the exceptions encompassed would easily exceed the *de minimis* level of emissions. The EPA has therefore, not adopted an increased cutoff limit for NO_X of 250 tons. Similarly, EPA concludes that an increased cutoff of 100 tons of NO_X would not be consistent with the type of source which the Agency has identified for use of the low mass emission excepted methodology or fit under the *de minimis* level of emissions defined for NO_X by the Agency. At the 100 ton cutoff for NO_X coupled to a 25 ton cutoff for SO_2 the aggregate NO_X emissions are 8841 tons of NO_X and 540 tons of SO_2 from 408 qualifying units. The analysis performed by the Agency indicates that 50 tons of NO_X coupled to 25 tons of SO_2 is the appropriate cutoff limit for applicability to the low mass emissions excepted methodology. The approximate aggregate emissions of 3600 tons of NO_X and 250 tons of SO_2 from 240 sources allows the appropriate type of units to use the provisions without great potential of exceeding a de-minimus level of NO_X emissions. In choosing the 50 ton NO_X mass emission cutoff limit over other limits, the Agency evaluated the available data and applied the following criteria: (1) The NO_X tons limit should allow reduced monitoring for the units which EPA determined were appropriate candidates for the low mass emissions provisions during the rulemaking process, namely units with low mass emissions both collectively and individually due to low operating levels or small size but not highly controlled units which operate at higher levels; (2) the NO_X tons limit should allow reduced monitoring for a group of units consistent with the level of *de minimis* emissions inventory for all exceptions for the CEMS requirement; and (3) the limit should not jeopardize the Agency's ability to effectively fulfill its obligations under of the CAA.

From the analysis performed, the Agency has demonstrated that increasing the 25 ton limit for SO_2 would result in allowing few additional sources the option to use the low mass emissions methodology. For example at a coupled 50 tons of NO_X and 25 tons of SO_2 increasing the SO_2 tonnage cutoff to 50 tons would allow only 7 additional units to use the methodology. The additional units identified all combusted oil as the primary fuel which has a very high sulfur content in comparison to natural gas. While natural gas fired units could easily increase operations without substantial increases in SO_2 emissions oil fired units could not. The additional units which burn oil and qualify are considered inappropriate candidates for use of the low mass emission provision. Therefore, the Agency has chosen to leave the tonnage limit at the proposed level of 25 tons for SO_2. Leaving the cutoff for applicability for SO_2 at 25 tons also reflected the opinion of commenters who suggested raising only the NO_X tonnage.

When considering the size cutoffs, EPA also took into account both the effect that the use of this methodology could have on other regulatory actions and the effect that other regulatory actions could have on the number of units and percentage of emissions that could be covered by units using this methodology. In particular, EPA was concerned about the SIP call. Units that could qualify to use the low mass emission methodology do not have a NO_X emission limit under title IV. However, under the SIP call, units that are using the monitoring requirements of part 75 to comply with the requirements of the SIP call, including units that could qualify to use the low mass emitter methodology, would have an emission limit. As explained in Section VI.A.2.c and VII.D.3 of today's preamble, EPA believes that it is important that large sources of NO_X mass emissions accurately account for their emissions. Because EPA is expecting substantial reductions in NO_X emissions from the title IV phase II NO_X emission rate limits, the SIP call and other similar programs, EPA believes that even if the total NO_X emissions coming from units that could qualify for the low mass emitter methodology does not increase, the percentage of emissions coming from these units will increase. The EPA also believes that the incentives provided under a trading program could encourage smaller oil and gas fired units that may not currently qualify under the low mass emission methodology to install controls. As a result, this could increase the number of units, the amount of emissions and the percentage of emissions that could be accounted for by units using this methodology. EPA believes that the 50 ton cutoff is adequate to ensure that emissions from units that qualify for the low mass emitter methodology are de-minimis today. In the future however, growth in the number of units may cause the level of NO_X, SO_2 or CO_2 emissions from units qualifying for and using the new unit exemption, appendix E, the low mass emitter provision and other programs such as the SIP call to exceed a de-minimis level and the agency reserves the right to re-assess any and all of these exceptions in the future if the need arises.

e. Decoupling NO_X and SO_2. In order to qualify for the low mass emissions excepted methodology, the applicability criteria require a unit to meet annual tonnage cutoffs of 25 tons for SO_2 and 50 tons for NO_X. The EPA has considered whether the excepted methodology should be available on a pollutant specific level so that, for example, a unit which falls below the tonnage cutoff for SO_2 but not for NO_X could use the excepted methodology under § 75.19 to measure SO_2 emissions but use a NO_X CEM or the excepted methodology under appendix E, where applicable, to measure NO_X emissions. All analysis the Agency has done indicates that the NO_X tonnage is the limiting factor for greater than 90 percent of all units when applicability is for units to meet a coupled 50 ton NO_X and 25 ton SO_2 limit (see Docket A–97–35, Items, II–A–10, IV–A–1) For example, approximately 20 units were identified which would potentially be qualified to use the low mass emission methodology for a 50 tons of NO_X cutoff who would not meet the 25 tons of SO_2 cutoff and therefore be disqualified from using the methodology. Conversely, the agency's analysis indicated that leaving the tonnage cutoff for SO_2 mass emissions at 25 tons and decoupling NO_X and SO_2 would potentially allow approximately 650 units in the program to use the low mass emissions methodology for SO_2 (see Docket A–97–35, Items, II–A–10, IV–A–1). In particular allowing decoupling could impair the Agency's ability to collect data on CO_2 emissions as required under the CAA section 821. The analysis performed by the Agency indicates, that even with a 25 ton limit on SO_2, 652 units could qualify for the use of the low mass emissions methodology for SO_2 only. The 652 units identified represent approximately 10 percent of the total program heat input and greater than 6 percent of the total program CO_2 emissions. If a unit which qualified for the use of only SO_2 were allowed to use the low mass emissions methodology for CO_2 the result could be overestimation of CO_2 emissions from a sizeable percentage of the total CO_2 inventory. Future decisions based on such data might draw incorrect conclusions.

For the reason stated above, if a unit were allowed to qualify for a single pollutant the unit would be allowed to use the low mass emissions methodology for that pollutant only and not for CO_2 or heat input estimations. Therefore, no practical benefit for industry would result from decoupling SO_2 and NO_X. Decoupling would not be particularly beneficial because qualifying for one pollutant only allows only minimal monitoring reductions when CO_2 and heat input are not simplified. In addition decoupling would dramatically increase the complexity of the low mass emissions methodology. The added complications which would benefit a limited number of sources in only a limited way would increase the time and effort needed for all other sources in understanding and implementing the methodology. The agency concludes that the burden from the increased rule complexity outweighs the benefit from decoupling SO_2 and NO_X.

The following discussions further explain the Agencies position.

One of the prime benefits of the low mass emissions excepted methodology will be the simplified reporting which will require less time and a less sophisticated Data Acquisition and Handling System (DAHS). In particular, the need for a DAHS that could calculate substitute data using the current missing data algorithms will be removed because there are no missing data algorithms for the low mass emissions excepted methodology. If the excepted methodology is only applied to one of the pollutants, much of the benefit would be negated because the DAHS will still need to be capable of calculating substitute data for the measured pollutant and close to the full quarterly report would still be required.

Another prime benefit of the low mass emissions excepted methodology will be the reduction of monitoring and quality assurance requirements. A unit which would qualify for SO_2 only would still need to determine CO_2 mass emissions using a fuel flow meter. Additionally the units which would qualify are primarily gas fired units which would be allowed to use appendix D for SO_2. In this case no benefit is allowed by using the low mass emissions methodology. A limited number of oil fired units would be granted some reduced sampling requirements.

The agency's analysis indicates that most units which would qualify for NO_X only can use the excepted methodology under appendix E.

As stated before the analysis indicates that the benefits of decoupling are outweighed by the complications of allowing decoupling.

f. The use of the Low Mass Emitter Methodology with fuels other than oil and natural gas. One commenter suggested that the applicability should be expanded to include other fuels including low sulfur solid fuels such as wood. EPA disagrees with the commenter who claims that the methodology should be irrespective of fuel type. The fuel type is an integral part of the emissions calculations and insures that emissions are not underestimated. The Agency does not have, and the commenter did not provide, sufficient data to justify including wood fired solid fuel units into the low mass emission methodology. The limited data EPA has does not provide assurance that wood is always low in sulfur or that it results in low mass emissions of NO_X. The use of AP 42 emission factors was considered but rejected based on the possibility of underestimation of NO_X emissions using the AP 42 factors, as stated in the January 11, 1993 rule preamble at 58 FR 364445. If EPA is provided with information addressing this issue in the future, EPA will consider expanding the applicability to units that burn wood in the future.

2. Method for Determining Emissions

On May 21, 1998 the Agency proposed a low mass emissions methodology which used maximum rated heat input as the only heat input option and default emission rates for SO_2, NO_X, and CO_2. The Agency requested comment on whether this methodology was appropriate or whether an alternate approach should be adopted for low mass emitting units. In response, several commenters suggested changing the method for determining emissions. One commenter suggested allowing the use of unit-specific NO_X testing (see Docket A–97–35, Item IV–D–20). Another commenter suggested that long term fuel flow heat input be allowed as an alternative to the proposed maximum rated heat input (see Docket A–97–35, Item IV–D–13). Two other commenters suggested that further unspecified options be allowed for determining heat input (see Docket A–97–35, Items, IV–D–03, IV–G–02). Additionally several commenters suggested that the reduced monitoring under the low mass emission methodology was being limited to too few sources (see Docket A–97–35, Items, IV–D–07, IV–D–22, IV–D–23, IV–D–24, IV–G–03). Other commenters made the general suggestion that part 75 should be more consistent with the monitoring requirements of the OTC NO_X Budget Program. Finally the Agency received both comments and data which indicated that for uncontrolled gas fired turbines combusting both oil and gas the default emission rates for NO_X in proposed table 1b of § 75.19 (c) were potentially substantial underestimations of actual emission from these types of units (see Docket A–97–35, Item IV–D–22). Further analysis by the Agency provided supporting evidence that the emission rates in proposed 75.19 (c), table 1b, might underestimate emissions significantly for gas and oil fired turbines (see Docket A–97–35, Item IV–A–1). In response to these comments which reflected a general desire to expand the applicability of the low mass emission methodology through changes in both the heat input and NO_X emissions methodology, and in light of no negative comments reflecting opposition to allowing the low mass emission methodology, the Agency began analysis of what changes in the methods for determining heat input and NO_X emissions could be allowed without risk of underestimation of emissions, or negative environmental consequences. The Agency received no comments on changing either the SO_2 or CO_2 methods for determining emissions and therefore did not attempt to change these methodologies.

a. Adoption of the Proposed Methodology. In the proposal, the Agency considered several methods for determining the estimated emissions as the basis for applicability of the reduced monitoring and reporting excepted methodology. For each of the methods considered, rather than using actual measured sulfur and carbon values, CO_2, SO_2, and flow CEM readings, NO_X CEM readings, or NO_X values from an Appendix E NO_X-versus-heat input correlation, a facility will calculate the unit's emissions based on an emission rate factor and one of two heat input methodologies. Since the units that will qualify for the excepted methodology will still be accountable for reporting emissions to the Agency and surrendering allowances based on those emissions, where applicable, the emissions estimations will not just be used to determine if the unit qualifies under the exception; the reported estimations will also be used to determine compliance. Prior to the proposal, some industry representatives suggested that facilities would be willing to use a conservative emission estimate, such as a maximum potential emission rate times the maximum heat input, if it would allow them to save time and money currently spent on monitoring and quality assurance (see Docket A–97–35, Items II–D–30, II–D–43, II–D–45, II–E–13, and II–E–25). The Agency decided it was appropriate to retain the proposed methodologies of maximum rated heat input and default SO_2, NO_X and CO_2 emission rates for the final rule. It was also decided to allow increased applicability of the low mass emissions methodology through optional unit-specific NO_X emission rate determinations and the use of an optional heat input methodology (e.g., long term fuel flow).

b. Change in Table 1b, Default NO_X Emission Rates. In deciding to retain the proposed low mass emission methodology as part of the final rule the Agency had to consider that some values for NO_X emission rate in proposed table 1b of § 75.19 (c) had a high potential for underestimating emissions in at least some cases. The Agency acknowledged that increasing the default NO_X emission rates in table 1b of § 75.19 (c) will reduce the number of units allowed to use the low mass emissions methodology. Based on the comments received (see Docket A–97–35, Item IV–D–20) and to both allow increased applicability and increase the default rates to an appropriate level, the use of NO_X testing to determine units-specific NO_X emission rates will be allowed as an alternative option to using the default NO_X emission rates in table 1b of § 75.19 (c). Allowing the option of unit-specific NO_X emission rates will generate more realistic NO_X emission rates than the default NO_X emission rates in table 1b of § 75.19 (c) and will maintain some of the simplicity of the NO_X mass methodology from the low mass emissions methodology proposal.

The next issue was deciding which default NO_X emission rates in table 1b of § 75.19 (c) to raise and what level to raise the defaults to. As a first consideration the Agency noted that the default NO_X emission rates in table 1b of proposed § 75.19 (c) should be increased to the level at which it will be highly unlikely that any unit that performed testing will have a higher emission rate than the default. In this case, a source might opt to use a default which would knowingly underestimate emissions under certain operating conditions. Since all of the defaults used in table 1b of proposed § 75.19 (c) were based on the 90th percentile it is very likely that some units would have a higher emission rate than the NO_X emission rates in table 1b of proposed 75.19 (c). For this reason, all of the NO_X emission rate values in proposed table 1b were increased to a level which will ensure that units will not have higher tested emission rates than the default rates in Table 1b. A commenter suggested that these provisions be more consistent with the provisions for the Ozone Transport Commission (OTC), NO_X Budget Program (see Docket A–97–35, Item IV–D–13). The default emission rates the Agency decided to adopt are the default rates used in the OTC NO_X Budget Program (see Docket A–97–35, Item II–I–7). In the OTC NO_X Budget Program, units similar in emission characteristics to those who will qualify as low mass emission units under today's rule have the option of unit specific testing or unit generic default OTC NO_X emission rates. In the OTC NO_X Budget Program units have chosen both options based on owner or operator preference. Finally, adopting the NO_X Budget Program defaults creates consistency among programs which is a supplementary benefit.

c. Unit-Specific NO_X Emission Rate Testing. In considering the options for unit-specific NO_X emission rate testing the Agency had to address several concerns, including the following: (1) Units with NO_X controls who performed unit specific testing with the controls operating might have the potential to grossly underestimate emissions if the controls failed; (2) what sort of test would be appropriate for determining the low mass emissions methodology fuel -and-unit-specific NO_X emission rate; (3) how long a period should a source be allowed to use the unit-specific NO_X rate once determined through testing; (4) under what conditions should a source be required to retest for a new unit-specific NO_X emission rate; (5) for sources with historical reported emissions data using CEMS under part 75, what historical NO_X emission rate value might be appropriate for use in lieu of an initial test; and (6) if a source owns multiple identical units, should representative testing be allowed at some of the units to represent all units.

The first issue resolved was the use of Appendix E of Part 75 procedures for determination of a unit-specific NO_X emission rate for each fuel combusted by the unit. The unit-specific NO_X emission rate selected, for each fuel tested, will be the highest recorded NO_X emission rate from the test at any test load or operating condition multiplied by 1.15. Units which combust multiple fuels can use, for different fuels, either a unit-specific NO_X rate determined through testing or use the default NO_X emission rates listed in table 1b of § 75.19 (c). For example, a unit which primarily combusts oil but occasionally combusts natural gas could determine a unit-specific NO_X emission rate for oil through Appendix E testing and use the default NO_X emission rate from table 1b of § 75.19 (c) for gas. For hours in which a unit combusts multiple fuels in one hour, the unit must use the highest emission rate for that hour for all fuels combusted. In conducting the Appendix E test, the requirement for monitoring heat input to the unit during the test is removed as it is an unnecessary burden. The multiplier of 1.15 is required because of Agency analysis which indicates that appendix E testing is not representative of emissions at a given load at all times. In particular, the analysis of units with NO_X emission rate CEMS indicated that the NO_X emission rate can vary an average of 15 percent at a given load during different periods of operation. The most probable cause of the difference noted is variations in atmospheric moisture content. The agency notes that units which do appendix E testing during hot humid conditions would likely underestimate emissions during cooler less humid conditions. The Appendix E test was chosen for several reasons including: (1) many current Acid Rain sources which might qualify for the low mass emissions methodology already have performed Appendix E testing and will be allowed to use their historical Appendix E test data to determine a unit-specific NO_X emission rate without further requirements; (2) the requirements of Appendix E testing are already familiar to sources and contractors who may perform the testing, thus reducing further burden imposed by requiring new testing methodologies; (3) The use of the Appendix E test and the multiplier of 1.15 ensures that a unit uses a NO_X emission rate which will not underestimate emissions at any normal operating condition.

Once the Appendix E test was chosen, the use of a five year testing frequency was deemed appropriate as it matched the current Appendix E test period and matches the current permit renewal cycle.

A special provision was included in the low mass emission methodology to allow units with historical CEMS NO_X emission rate data to determine a unit-specific NO_X emission rate from historical certified CEMS data. Under this provision a unit will analyze historical data from hours in which a unit combusted a particular fuel. The analysis will determine the unit-specific NO_X emission rate which will yield a 95 percent confidence that the unit will not emit at a higher NO_X emission rate while combusting the fuel being analyzed. The Agency also considered using the highest NO_X rate from historical data but reasoned that the large data sets used to generate the unit- and fuel-specific emission rate would contain outliers which would make the procedure unfeasible for most units. The Agency considered several options for units which used NO_X controls and wished to use unit-specific NO_X emission rates determined through Appendix E testing. One option was to allow units to test with the NO_X control devices not operating or minimized. This option was rejected for the following two reasons: (1) the Agency does not support adopting a rule which would require sources to operate in a manner that would increase emissions; and (2) some sources which have controls are not allowed to operate when the controls are not operating by permit restrictions and these units would be disallowed from using the low mass emission methodology unfairly. The Agency also considered not allowing units with NO_X emission controls to use the low mass emission methodology. While the Agency does believe that it is *not* appropriate to include large controlled units, the Agency does feel it is appropriate to allow infrequently used controlled units, such as peaking turbines with steam or water injection to benefit from the reduced requirements of this methodology (as further explained above). Therefore this solution was rejected as excluding many units for which the Agency believes it is appropriate to allow reduced monitoring from more accurate and more costly monitoring requirements.

The Agency also considered allowing only units with certain types of controls to use the low mass emission methodology. This approach was rejected because the Agency does not, at this time, have the necessary information or expertise to make an appropriate determination on this approach.

The Agency also considered allowing units to determine a unit-specific NO_X emission rate using NO_X controls with no restriction. In analyzing this option, the Agency identified several units which would qualify for the low mass emission methodology based on the applicability criteria of 50 tons of NO_X and 25 tons of SO_2 which the Agency did not believe were appropriate to use the low mass emission methodology. The units identified had advanced control technologies such as selective catalytic reduction (SCR) and burned low sulfur fuels such as natural gas. The units identified consistently reported hourly emission rates as low as 0.01 lb/mmBtu as compared to uncontrolled rates which are generally 10 to 100 times higher for these units. The best method of continued assurance that a unit's NO_X controls are operating is monitoring with a NO_X CEMS. These units also operated during more than half the hours of a year at an average heat input of greater than 1000 mmBtu/hr. While, for these units, the potential to underestimate SO_2 emissions was low, the potential to grossly underestimate NO_X mass emissions using the low mass emission methodology was much greater. For this reason, the Agency rejected allowing a controlled unit to use a single emission rate determined through Appendix E testing once every five years while NO_X controls were operating.

The methodology the Agency adopted in this rule was the use of a lower limit of 0.15 lb/mmBtu for a unit-specific NO_X emission rate for units which opt to perform unit-and fuel-specific Appendix E testing while controls are operating. For units with NO_X emission controls, which perform unit-specific NO_X emission rate testing and whose test results in a NO_X emission rate of less than 0.15 lb/mmBtu, the source will use the NO_X emission rate limit of 0.15 lb/mmBtu for the unit-specific NO_X emission rate instead of the lower tested NO_X emission rate. Units with NO_X emission controls who perform unit-specific NO_X emission rate testing and whose results from the testing indicate a NO_X emission rate of higher than 0.15 lb/mmBtu will be required to use the higher NO_X emission rate as the fuel- and unit-specific NO_X emission rate. In considering this approach the Agency considered using the lowest NO_X emission rate proposed in 75.19 (c), Table 1b, of 0.172 lb/mmBtu, as well as 0.15 lb/mmBtu, 0.1 lb/mmBtu and 0.05 lb/mmBtu as lower limits for NO_X emission rate. The proposed gas fired turbine emission rate was 0.172 lb/mmBtu. Using 0.172 lb/mmBtu as the lower limit for controlled units was rejected as being an arbitrary choice based on a number representative of only a single class of units and not representative of the difference between controlled and uncontrolled units. An analysis was performed to determine a reasonable lower cutoff between controlled and uncontrolled units which would allow controlled units to qualify for the reduced monitoring provisions of the excepted low mass emission methodology without serious risk of underestimation of emissions. The analysis indicated that a minimum allowable emission rate of 0.15 lb/mmBtu for controlled units best allowed for fairness between controlled and uncontrolled units and insured that very large units with high operating hours and extremely low NO_X emission rates will not be allowed to use the low mass emission excepted methodology. The Agency's decision was also heavily influenced by the desire to insure that overall, the emission rate chosen would insure that aggregate emissions of controlled units were indeed *de minimis.* The Agency notes that the lower limit of 0.15 lb/mmBtu NO_X emission rate, when coupled with the annual limit of 50 tons of NO_X, effectively limits the annual heat input of units using the methodology to 666,666 mmBtu annual heat input. Analysis done by EPA found this to be an appropriate limit on heat input for the low mass emission excepted methodology (see Docket A–97–35, Item IV–D–20). In general, the lower emission rate limit for controlled units, and uncontrolled units inability to achieve such low rates, combines to limit the low mass emission methodology to the infrequently operated low mass emitting units the Agency was targeting for use of the provision in today's new rule.

Controlled units that use this methodology are also subject to additional requirements. The owner or operator of the unit must ensure that the controls are being operated in the same manner that they were operated during the unit specific testing. Documentation of this must be kept on site. Any hour that the controls are not operating properly, the owner or operator must use the default emission rates for NO_X in table 1.b of § 75.19 (c), rather than the emission rate determined through unit specific testing.

Based on experience gained working with the OTC in the implementation of the OTC NO_X budget program, EPA believes that many of the units that may benefit from this new excepted monitoring methodology are banks of identical small emission turbines. The OTC has allowed these units to do representative sampling at a number of units rather than requiring testing at all of the units. While none of the commenters mentioned this specific flexibility of the OTC NO_X Budget program, EPA believes that this is one of the flexibilities that commenters who suggested adopting some of the methodologies that the OTC has allowed for smaller units were referring to. Therefore this final rule contains a similar allowance for identical units. If the owner or operator of a number of units that are located at one facility can demonstrate that those units are identical, this final rule will allow emission rate testing to be done at a representative number of units.

d. The Adoption of Maximum Rated Heat Input as Proposed. While several commenters suggested allowing alternative methods for determining heat input, none directly suggested replacing or altering the basic heat input approach as an option (as described in 68 FR 28037–8). For this reason the maximum rated hourly heat input option from the proposal was retained as a less accurate but acceptable approach.

e. Long Term Fuel Flow for Heat Input Determination. To allow greater flexibility to units under the low mass emissions methodology and to allow more realistic estimations of heat input as suggested by several commenters the Agency is allowing the use of long term fuel flow measurements to determine heat input to low mass emitting units as described earlier. The Agency chose to adopt this methodology for the following reasons: (1) The methodology allows more accurate measurements of total heat input into a unit over the reporting period than the use of maximum rated hourly heat input; (2) the methodology has proven to be usable by sources who have chosen to use a similar method in the Ozone Transport Commission, NO_X Budget Program; and (3) the methodology is straightforward and is optional for sources which might be excluded from using the low mass emissions methodology if allowed to use maximum rated hourly heat input only.

3. Reduced Monitoring and Quality Assurance Requirements. As discussed above, today's rule allows facilities to use a maximum rated hourly heat input value and an emission rate factor to determine the mass emissions from a low-emitting unit for each hour of actual operation. This approach involves no actual emissions monitoring and minimal quality assurance activities. Instead, the facility will only need to keep track of whether the unit combusted any fuel for a particular hour and what type of fuel was combusted. In this way, the revised rule significantly reduces the burden on affected facilities, while still ensuring that emissions are not under reported.

For owners or operators which opt to use either the long term fuel flow methodology or a fuel-and unit-specific NO_X emission rate, some additional quality assurance will be required. As these two options under the low mass emission methodology are not required and will allow units which would not otherwise qualify to use the low mass emission methodology, the additional quality assurance requirements are not burdensome to the sources using either long term fuel flow or unit-specific NO_X emission rates.

For the reasons set forth in the preamble, parts 51, 72, 75, and 96 of chapter I of title 40 of the Code of Federal Regulations 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

2. Subpart G is amended to add §§ 51.121 and 51.122 to read as follows:

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

(a)(1) The Administrator finds that the State implementation plan (SIP) for each jurisdiction listed in paragraph (c) of this section is substantially inadequate to comply with the requirements of section 110(a)(2)(D)(i)(I) of the Clean Air Act (CAA), 42 U.S.C. 7410(a)(2)(D)(i)(I), because the SIP does not include adequate provisions to prohibit sources and other activities from emitting nitrogen oxides (''NO_X'') in amounts that will contribute significantly to nonattainment in one or more other States with respect to the 1-hour ozone national ambient air quality standards (NAAQS). Each of the jurisdictions listed in paragraph (c) of this section must submit to EPA a SIP revision that cures the inadequacy.

(2) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each jurisdiction listed in paragraph (c) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I), 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the 8-hour ozone NAAQS.

(b)(1) For each jurisdiction listed in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision:

(i) Contains control measures adequate to prohibit emissions of NO_X that would otherwise be projected, in accordance with paragraph (g) of this section, to cause the jurisdiction's overall NO_X emissions to be in excess of the budget for that jurisdiction described in paragraph (e) of this section (except as provided in paragraph (b)(2) of this section),

(ii) Requires full implementation of all such control measures by no later than May 1, 2003, and

(iii) Meets the other requirements of this section. The SIP revision's compliance with the requirement of paragraph (b)(1)(i) of this section shall be considered compliance with the jurisdiction's budget for purposes of this section.

(2) The requirements of paragraph (b)(1)(i) of this section shall be deemed satisfied, for the portion of the budget covered by an interstate trading program, if the SIP revision:

(i) Contains provisions for an interstate trading program that EPA determines will, in conjunction with interstate trading programs for one or more other jurisdictions, prohibit NO_X emissions in excess of the sum of the portion of the budgets covered by the trading programs for those jurisdictions; and

(ii) Conforms to the following criteria:

(A) Emissions reductions used to demonstrate compliance with the revision must occur during the ozone season.

(B) Emissions reductions occurring prior to the year 2003 may be used by a source to demonstrate compliance with the SIP revision for the 2003 and 2004 ozone seasons, provided the SIP's provisions regarding such use comply with the requirements of paragraph (e)(3) of this section.

(C) Emissions reduction credits or emissions allowances held by a source or other person following the 2003 ozone season or any ozone season thereafter that are not required to demonstrate compliance with the SIP for the relevant ozone season may be banked and used to demonstrate compliance with the SIP in a subsequent ozone season.

(D) Early reductions created according to the provisions in paragraph (b)(2)(ii)(B) of this section and used in the 2003 ozone season are not subject to the flow control provisions set forth in paragraph (b)(2)(ii)(E) of this section.

(E) Starting with the 2004 ozone season, the SIP shall include provisions to limit the use of banked emissions reduction credits or emissions allowances beyond a predetermined amount as calculated by one of the following approaches:

(*1*) Following the determination of compliance after each ozone season, if the total number of emissions reduction credits or banked allowances held by sources or other persons subject to the trading program exceeds 10 percent of the sum of the allowable ozone season NO_X emissions for all sources subject to the trading program, then all banked allowances used for compliance for the following ozone season shall be subject to the following:

(*i*) A ratio will be established according to the following formula: (0.10) × (the sum of the allowable ozone season NO_X emissions for all sources subject to the trading program) ÷ (the total number of banked emissions reduction credits or emissions allowances held by all sources or other persons subject to the trading program).

(*ii*) The ratio, determined using the formula specified in paragraph (b)(2)(ii)(E)(1)(i) of this section, will be multiplied by the number of banked emissions reduction credits or emissions allowances held in each account at the time of compliance determination. The resulting product is the number of banked emissions reduction credits or emissions allowances in the account which can be used in the current year's ozone season at a rate of 1 credit or allowance for every 1 ton of emissions. The SIP shall specify that banked emissions reduction credits or emissions allowances in excess of the resulting product either may not be used for compliance, or may only be used for compliance at a rate no less than 2 credits or allowances for every 1 ton of emissions.

(*2*) At the time of compliance determination for each ozone season, if the total number of banked emissions reduction credits or emissions allowances held by a source subject to the trading program exceeds 10 percent of the source's allowable ozone season NO_X emissions, all banked emissions reduction credits or emissions allowances used for compliance in such ozone season by the source shall be subject to the following:

(*i*) The source may use an amount of banked emissions reduction credits or emissions allowances not greater than 10 percent of the source's allowable ozone season NO_X emissions for compliance at a rate of 1 credit or allowance for every 1 ton of emissions.

(*ii*) The SIP shall specify that banked emissions reduction credits or emissions allowances in excess of 10 percent of the source's allowable ozone season NO_X emissions may not be used for compliance, or may only be used for compliance at a rate no less than 2 credits or allowances for every 1 ton of emissions.

(c) The following jurisdictions (hereinafter referred to as ''States'') are subject to the requirements of this section: Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin, and the District of Columbia.

(d)(1) The SIP submissions required under paragraph (a) of this section must be submitted to EPA by no later than September 30, 1999.

(2) The State makes an official submission of its SIP revision to EPA only when:

(i) The submission conforms to the requirements of appendix V to this part; and

(ii) The State delivers five copies of the plan to the appropriate Regional Office, with a letter giving notice of such action.

(e)(1) The NO_X budget for a State listed in paragraph (c) of this section is defined as the total amount of NO_X emissions from all sources in that State, as indicated in paragraph (e)(2) of this section with respect to that State, which the State must demonstrate that it will not exceed in the 2007 ozone season pursuant to paragraph (g)(1) of this section.

(2) The State-by-State amounts of the NO_X budget, expressed in tons, are as follows:

State	Budget
Alabama	158,677
Connecticut	40,573
Delaware	18,523
District of Columbia	6,792
Georgia	177,381
Illinois	210,210
Indiana	202,584
Kentucky	155,698
Maryland	71,388
Massachusetts	78,168
Michigan	212,199
Missouri	114,532
New Jersey	97,034
New York	179,769
North Carolina	151,847
Ohio	239,898
Pennsylvania	252,447
Rhode Island	8,313
South Carolina	109,425
Tennessee	182,476
Virginia	155,718
West Virginia	92,920
Wisconsin	106,540
Total	3,023,113

(3)(i) Notwithstanding the State's obligation to comply with the budgets set forth in paragraph (e)(2) of this section, a SIP revision may allow sources required by the revision to implement NO_X emission control measures by May 1, 2003 to demonstrate compliance in the 2003 and 2004 ozone seasons using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(3)(iii) of this section.

(ii) A source may not use credit from the compliance supplement pool to demonstrate compliance after the 2004 ozone season.

(iii) The State-by-State amounts of the compliance supplement pool are as follows:

State	Compliance supplement pool (tons of NO_X)
Alabama	10,361
Connecticut	559
Delaware	417
District of Columbia	0
Georgia	10,919
Illinois	17,455
Indiana	19,738
Kentucky	13,018
Maryland	3,662
Massachusetts	285
Michigan	15,359
Missouri	10,469
New Jersey	1,722
New York	1,831
North Carolina	10,624
Ohio	22,947
Pennsylvania	13,716
Rhode Island	0
South Carolina	5,062
Tennessee	12,093
Virginia	6,108
West Virginia	16,937
Wisconsin	6,717
Total	200,000

(iv) The SIP revision may provide for the distribution of the compliance supplement pool to sources that are required to implement control measures using one or both of the following two mechanisms:

(A) The State may issue some or all of the compliance supplement pool to sources that implement emissions reductions during the ozone season beyond all applicable requirements in years prior to the year 2003 according to the following provisions:

(1) The State shall complete the issuance process by no later than May 1, 2003.

(2) The emissions reduction may not be required by the State's SIP or be otherwise required by the CAA.

(*3*) The emissions reduction must be verified by the source as actually having occurred during an ozone season between September 30, 1999 and May 1, 2003.

(*4*) The emissions reduction must be quantified according to procedures set forth in the SIP revision and approved by EPA. Emissions reductions implemented by 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, must be quantified according to the requirements in paragraph (i)(4) of this section.

(*5*) If the SIP revision contains approved provisions for an emissions trading program, sources that receive credit according to the requirements of this paragraph may trade the credit to other sources or persons according to the provisions in the trading program.

(B) The State may issue some or all of the compliance supplement pool to sources that demonstrate a need for an extension of the May 1, 2003 compliance deadline according to the following provisions:

(*1*) The State shall initiate the issuance process by the later date of September 30, 2002 or after the State issues credit according to the procedures in paragraph (e)(3)(iv)(A) of this section.

(*2*) The State shall complete the issuance process by no later than May 1, 2003.

(*3*) The State shall issue credit to a source only if the source demonstrates the following:

(*i*) For a source used to generate electricity, compliance with the SIP revision's applicable control measures by May 1, 2003, would create undue risk for the reliability of the electricity supply. This demonstration must include a showing that it would not be feasible to import electricity from other electricity generation systems during the installation of control technologies necessary to comply with the SIP revision.

(*ii*) For a source not used to generate electricity, compliance with the SIP revision's applicable control measures by May 1, 2003, would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(3)(iv)(B)(3)(i) of this section.

(*iii*) For a source subject to an approved SIP revision that allows for early reduction credits in accordance with paragraph (e)(3)(iv)(A) of this section, it was not possible for the source to comply with applicable control measures by generating early reduction credits or acquiring early reduction credits from other sources.

(*iv*) For a source subject to an approved emissions trading program, it was not possible to comply with applicable control measures by acquiring sufficient credit from other sources or persons subject to the emissions trading program.

(*4*) The State shall ensure the public an opportunity, through a public hearing process, to comment on the appropriateness of allocating compliance supplement pool credits to a source under paragraph (e)(3)(iv)(B) of this section.

(4) If, no later than November 23, 1998, any member of the public requests revisions to the source-specific data 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 January 22, 1999, provided:

(i) The request is submitted in electronic format;

(ii) Information is provided to corroborate and justify the need for the requested modification;

(iii) The request includes the following data information regarding any electricity-generating source at issue:

(A) Federal Information Placement System (FIPS) State Code;

(B) FIPS County Code;

(C) Plant name;

(D) Plant ID numbers (ORIS code preferred, State agency tracking number also or otherwise);

(E) Unit ID numbers (a unit is a boiler or other combustion device);

(F) Unit type;

(G) Primary fuel on a heat input basis;

(H) Maximum rated heat input capacity of unit;

(I) Nameplate capacity of the largest generator the unit serves;

(J) Ozone season heat inputs for the years 1995 and 1996;

(K) 1996 (or most recent) average NO_X rate for the ozone season;

(L) Latitude and longitude coordinates;

(M) Stack parameter information ;

(N) Operating parameter information;

(o) Identification of specific change to the inventory; and

(p) Reason for the change;

(iv) The request includes the following data information regarding any non-electricity generating point source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Plant name;

(D) Facility primary standard industrial classification code (SIC);

(E) Plant ID numbers (NEDS, AIRS/AFS, and State agency tracking number also or otherwise);

(F) Unit ID numbers (a unit is a boiler or other combustion device);

(G) Primary source classification code (SCC);

(H) Maximum rated heat input capacity of unit;

(I) 1995 ozone season or typical ozone season daily NO_X emissions;

(J) 1995 existing NO_X control efficiency;

(K) Latitude and longitude coordinates;

(L) Stack parameter information;

(M) Operating parameter information;

(N) Identification of specific change to the inventory; and

(O) Reason for the change;

(v) The request includes the following data information regarding any stationary area source or nonroad mobile source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Primary source classification code (SCC);

(D) 1995 ozone season or typical ozone season daily NO_X emissions;

(E) 1995 existing NO_X control efficiency;

(F) Identification of specific change to the inventory; and

(G) Reason for the change;

(vi) The request includes the following data information regarding any highway mobile source at issue:

(A) FIPS State Code;

(B) FIPS County Code;

(C) Primary source classification code (SCC) or vehicle type;

(D) 1995 ozone season or typical ozone season daily vehicle miles traveled (VMT);

(E) 1995 existing NO_X control programs;

(F) identification of specific change to the inventory; and

(G) reason for the change.

(f) Each SIP revision must set forth control measures to meet the NO_X budget in accordance with paragraph (b)(1)(i) of this section, which include the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2) Should a State elect 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 as a means of meeting its NO_X budget, then those measures must:

(i)(A) Impose a NO_X mass emissions cap on each source;

(B) Impose a NO_X emissions rate limit on each source and assume maximum operating capacity for every such source for purposes of estimating mass NO_X emissions; or

(C) Impose any other regulatory requirement which the State has demonstrated to EPA provides equivalent or greater assurance than options in paragraphs (f)(2)(i)(A) or (f)(2)(i)(B) of this section that the State will comply with its NO_X budget in the 2007 ozone season; and

(ii) Impose enforceable mechanisms 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.

(3) For purposes of paragraph (f)(2) of this section, the term ''fossil fuel-fired'' means, with regard to a NO_X source:

(i) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a NO_X source had no heat input starting in 1995, during the last year of operation of the NO_X source prior to 1995; or

(ii) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the NO_X source shall be ''fossil fuel-fired'' as of the date, during such year, on which the NO_X source begins combusting fossil fuel.

(g)(1) Each SIP revision must demonstrate that the control measures contained in it are adequate to provide for the timely compliance with the State's NO_X budget during the 2007 ozone season.

(2) The demonstration must include the following:

(i) Each revision must contain a detailed baseline inventory of NO_X mass emissions from the following sources in the year 2007, absent the control measures specified in the SIP submission: electric generating units (EGU), non-electric generating units (non-EGU), area, nonroad and highway sources. The State must use the same baseline emissions inventory that EPA used in calculating the State's NO_X budget, as set forth for the State in paragraph (g)(2)(ii) of this section, except that EPA may direct the State to use different baseline inventory information if the State fails to certify that it has implemented all of the control measures assumed in developing the baseline inventory.

(ii) The base year 2007 NO_X emissions sub-inventories for each State, expressed in tons per ozone season, are as follows:

State	EGU	Non-EGU	Area	Nonroad	Highway	Total
Alabama	76,900	49,781	25,225	16,594	50,111	218,610
Connecticut	5,600	5,273	4,588	9,584	18,762	43,807
Delaware	5,800	1,781	963	4,261	8,131	20,936
District of Columbia	[1] 0	310	741	3,470	2,082	6,603
Georgia	86,500	33,939	11,902	21,588	86,611	240,540
Illinois	119,300	55,721	7,822	47,035	81,297	311,174
Indiana	136,800	71,270	25,544	22,445	60,694	316,753
Kentucky	107,800	18,956	38,773	19,627	45,841	230,997
Maryland	32,600	10,982	4,105	17,249	27,634	92,570
Massachusetts	16,500	9,943	10,090	18,911	24,371]	79,815
Michigan	86,600	79,034	28,128	23,495	83,784	301,042
Missouri	82,100	13,433	6,603	17,723	55,230	175,089
New Jersey	18,400	22,228	11,098	21,163	34,106	106,995
New York	39,200	25,791	15,587	29,260	80,521	190,358
North Carolina	84,800	34,027	10,651	17,799	66,019	213,296
Ohio	163,100	53,241	19,425	37,781	99,079	372,626
Pennsylvania	123,100	73,748	17,103	25,554	92,280	331,785

State	EGU	Non-EGU	Area	Nonroad	Highway	Total
Rhode Island	1,100	327	420	2,073	4,375	8,295
South Carolina	36,300	34,740	8,359	11,903	47,404	138,706
Tennessee	70,900	60,004	11,990	44,567	64,965	252,426
Virginia	40,900	39,765	18,622	21,551	70,212	191,050
West Virginia	115,500	40,192	4,790	10,220	20,185	190,887
Wisconsin	52,000	22,796	8,160	12,965	49,470	145,391
Total	1,501,800	757,281	290,689	456,818	1,173,163	4,179,751

[1] The base case for the District of Columbia is actually projected to be 30 tons per season. The base case values in this table are rounded to the nearest 100 tons.

(iii) Each revision must contain a summary of NO_X mass emissions in 2007 projected to result from implementation of each of the control measures specified in the SIP submission and from all NO_X sources together following implementation of all such control measures, compared to the baseline 2007 NO_X emissions inventory for the State described in paragraph (g)(2)(i) of this section. The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2007 NO_X emissions that will be achieved from the implementation of the new control measures compared to the baseline emissions inventory.

(iv) Each revision must identify the sources of the data used in the projection of emissions.

(h) Each revision must comply with § 51.116 of this part (regarding data availability).

(i) Each revision must provide for monitoring the status of compliance with any control measures adopted to meet the NO_X budget. Specifically, the revision must meet the following requirements:

(1) The revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The revision must comply with § 51.212 of this part (regarding testing, inspection, enforcement, and complaints);

(3) If the revision contains any transportation control measures, then the revision must comply with § 51.213 of this part (regarding transportation control measures);

(4) If the revision contains measures to control 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, then the revision must require such sources to comply with the monitoring provisions of part 75, subpart H.

(5) For purposes of paragraph (i)(4) of this section, the term ''fossil fuel-fired'' means, with regard to a NO_X source:

(i) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a NO_X source had no heat input starting in 1995, during the last year of operation of the NO_X source prior to 1995; or

(ii) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year, provided that the NO_X source shall be ''fossil fuel-fired'' as of the date, during such year, on which the NO_X source begins combusting fossil fuel.

(j) Each revision must show that the State has legal authority to carry out the revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's NO_X budget specified in paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards, and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources;

(4) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; also authority for the State to make such data available to the public as reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation which the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(l)(1) A revision may assign legal authority to local agencies in accordance with § 51.232 of this part.

(2) Each revision must comply with § 51.240 of this part (regarding general plan requirements).

(m) Each revision must comply with § 51.280 of this part (regarding resources).

(n) For purposes of the SIP revisions required by this section, EPA may make a finding as applicable under section 179(a)(1)–(4) of the CAA, 42 U.S.C. 7509(a)(1)–(4), starting the sanctions process set forth in section 179(a) of the CAA. Any such finding will be deemed a finding under § 52.31(c) of this part and sanctions will be imposed in accordance with the order of sanctions and the terms for such sanctions established in § 52.31 of this part.

(o) Each revision must provide for State compliance with the reporting requirements set forth in § 51.122 of this part.

(p)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to 40 CFR part 96 (the model NO_X budget trading program for SIPs), incorporates such part by reference into its regulations, or adopts regulations that differ substantively from such part only as set forth in paragraph (p)(2) of this section, then that portion of the State's SIP revision is automatically approved as satisfying the same portion of the State's NO_X emission reduction obligations as the State projects such regulations will satisfy, provided that:

(i) The State has the legal authority to take such action and to implement its responsibilities under such regulations, and

(ii) The SIP revision accurately reflects the NO_X emissions reductions to be expected from the State's implementation of such regulations.

(2) If a State adopts an emissions trading program that differs substantively from 40 CFR part 96 in only the following respects, then such portion of the State's SIP revision is approved as set forth in paragraph (p)(1) of this section:

(i) The State may expand the applicability provisions of the trading program to include units (as defined in 40 CFR 96.2) that are smaller than the size criteria thresholds set forth in 40 CFR 96.4(a);

(ii) The State may decline to adopt the exemption provisions set forth in 40 CFR 96.4(b);

(iii) The State may decline to adopt the opt-in provisions set forth in subpart I of 40 CFR part 96;

(iv) The State may decline to adopt the allocation provisions set forth in subpart E of 40 CFR part 96 and may instead adopt any methodology for allocating NO_X allowances to individual sources, provided that:

(A) The State's methodology does not allow the State to allocate NO_X allowances in excess of the total amount of NO_X emissions which the State has assigned to its trading program; and

(B) The State's methodology conforms with the timing requirements for submission of allocations to the Administrator set forth in 40 CFR 96.41; and

(v) The State may decline to adopt the early reduction credit provisions set forth in 40 CFR 96.55(c) and may instead adopt any methodology for issuing credit from the State's compliance supplement pool that complies with paragraph (e)(3) of this section.

(3) If a State adopts an emissions trading program that differs substantively from 40 CFR part 96 other than as set forth in paragraph (p)(2) of this section, then such portion of the State's SIP revision is not automatically approved as set forth in paragraph (p)(1) of this section but will be reviewed by the Administrator for approvability in accordance with the other provisions of this section.

§ 51.122 Emissions reporting requirements for SIP revisions relating to budgets for NO_X emissions

(a) For its transport SIP revision under § 51.121 of this part, each State must submit to EPA NO_X emissions data as described in this section.

(b) Each revision must provide for periodic reporting by the State of NO_X emissions data to demonstrate whether the State's emissions are consistent with the projections contained in its approved SIP submission.

(1) *Annual reporting.* Each revision must provide for annual reporting of NO_X emissions data as follows:

(i) The State must report to EPA emissions data from all NO_X sources within the State for which the State specified control measures in its SIP submission under § 51.121(g) of this part. This would include all sources for which the State has adopted measures that differ from the measures incorporated into the baseline inventory for the year 2007 that the State developed in accordance with § 51.121(g) of this part.

(ii) If sources report NO_X emissions data to EPA annually pursuant to a trading program approved under § 51.121(p) of this part or pursuant to the monitoring and reporting requirements of subpart H of 40 CFR part 75, then the State need not provide annual reporting to EPA for such sources.

(2) *Triennial reporting.* Each plan must provide for triennial (i.e., every third year) reporting of NO_X emissions data from all sources within the State.

(3) *Year 2007 reporting.* Each plan must provide for reporting of year 2007 NO_X emissions data from all sources within the State.

(4) The data availability requirements in § 51.116 of this part must be followed for all data submitted to meet the requirements of paragraphs (b)(1),(2) and (3) of this section.

(c) The data reported in paragraph (b) of this section for stationary point sources must meet the following minimum criteria:

(1) For annual data reporting purposes the data must include the following minimum elements:

(i) Inventory year.
(ii) State Federal Information Placement System code.
(iii) County Federal Information Placement System code.
(iv) Federal ID code (plant).
(v) Federal ID code (point).
(vi) Federal ID code (process).
(vii) Federal ID code (stack).
(vii) Site name.
(viii) Physical address.
(ix) SCC.
(x) Pollutant code.
(xi) Ozone season emissions.
(xii) Area designation.

(2) In addition, the annual data must include the following minimum elements as applicable to the emissions estimation methodology.

(i) Fuel heat content (annual).
(ii) Fuel heat content (seasonal).
(iii) Source of fuel heat content data.
(iv) Activity throughput (annual).
(v) Activity throughput (seasonal).
(vi) Source of activity/throughput data.
(vii) Spring throughput (%).
(viii) Summer throughput (%).
(ix) Fall throughput (%).
(x) Work weekday emissions.
(xi) Emission factor.
(xii) Source of emission factor.
(xiii) Hour/day in operation.
(xiv) Operations Start time (hour).
(xv) Day/week in operation.
(xvi) Week/year in operation.

(3) The triennial and 2007 inventories must include the following data elements:

(i) The data required in paragraphs (c)(1) and (c)(2) of this section.
(ii) X coordinate (latitude).
(iii) Y coordinate (longitude).
(iv) Stack height.
(v) Stack diameter.
(vi) Exit gas temperature.
(vii) Exit gas velocity.
(viii) Exit gas flow rate.
(ix) SIC.
(x) Boiler/process throughput design capacity.
(xi) Maximum design rate.
(xii) Maximum capacity.
(xiii) Primary control efficiency.
(xiv) Secondary control efficiency.
(xv) Control device type.

(d) The data reported in paragraph (b) of this section for area sources must include the following minimum elements:

(1) For annual inventories it must include:

(i) Inventory year.
(ii) State FIPS code.
(iii) County FIPS code.
(iv) SCC.
(v) Emission factor.
(vi) Source of emission factor.
(vii) Activity/throughput level (annual).
(viii) Activity throughput level (seasonal).
(ix) Source of activity/throughput data.
(x) Spring throughput (%).
(xi) Summer throughput (%).
(xii) Fall throughput (%).
(xiii) Control efficiency (%).
(xiv) Pollutant code.
(xv) Ozone season emissions.
(xvi) Source of emissions data.
(xvii) Hour/day in operation.
(xviii) Day/week in operation.
(xix) Week/year in operations.

(2) The triennial and 2007 inventories must contain, at a minimum, all the data required in paragraph (d)(1) of this section.

(e) The data reported in paragraph (b) of this section for mobile sources must meet the following minimum criteria:

(1) For the annual, triennial, and 2007 inventory purposes, the following data must be reported:

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.

(iv) SCC.

(v) Emission factor.

(vi) Source of emission factor.

(vii) Activity (this must be reported for both highway and nonroad activity. Submit nonroad activity in the form of hours of activity at standard load (either full load or average load) for each engine type, application, and horsepower range. Submit highway activity in the form of vehicle miles traveled (VMT) by vehicle class on each roadway type. Report both highway and nonroad activity for a typical ozone season weekday day, if the State uses EPA's default weekday/weekend activity ratio. If the State uses a different weekday/weekend activity ratio, submit separate activity level information for weekday days and weekend days).

(viii) Source of activity data.

(ix) Pollutant code.

(x) Summer work weekday emissions.

(xi) Ozone season emissions.

(xii) Source of emissions data.

(2) [Reserved]

(f) *Approval of ozone season calculation by EPA.* Each State must submit for EPA approval an example of the calculation procedure used to calculate ozone season emissions along with sufficient information for EPA to verify the calculated value of ozone season emissions.

(g) *Reporting schedules.* (1) Annual reports are to begin with data for emissions occurring in the year 2003.

(2) Triennial reports are to begin with data for emissions occurring in the year 2002.

(3) Year 2007 data are to be submitted for emissions occurring in the year 2007.

(4) States must submit data for a required year no later than 12 months after the end of the calendar year for which the data are collected.

(h) *Data reporting procedures.* When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.

(1) States are required to report emissions data in an electronic format to one of the locations listed in this paragraph (h). Several options are available for data reporting.

(2) An agency may choose to continue reporting to the EPA Aerometric Information Retrieval System (AIRS) system using the AIRS facility subsystem (AFS) format for point sources. (This option will continue for point sources for some period of time after AIRS is reengineered (before 2002), at which time this choice may be discontinued or modified.)

(3) An agency may convert its emissions data into the Emission Inventory Improvement Program/Electronic Data Interchange (EIIP/EDI) format. This file can then be made available to any requestor, either using E-mail, floppy disk, or value added network (VAN), or can be placed on a file transfer protocol (FTP) site.

(4) An agency may submit its emissions data in a proprietary format based on the EIIP data model.

(5) For options in paragraphs (h)(3) and (4) of this section, the terms submitting and reporting data are defined as either providing the data in the EIIP/EDI format or the EIIP based data model proprietary format to EPA, Office of Air Quality Planning and Standards, Emission Factors and Inventory Group, directly or notifying this group that the data are available in the specified format and at a specific electronic location (e.g., FTP site).

(6) For annual reporting (not for triennial reports), a State may have sources submit the data directly to EPA to the extent the sources are subject to a trading program that qualifies for approval under § 51.121(q) of this part, and the State has agreed to accept data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.

(i) *Definitions.* As used in this section, the following words and terms shall have the meanings set forth below:

(1) *Annual emissions.* Actual emissions for a plant, point, or process, either measured or calculated.

(2) *Ash content.* Inert residual portion of a fuel.

(3) *Area designation.* The designation of the area in which the reporting source is located with regard to the ozone NAAQS. This would include attainment or nonattainment designations. For nonattainment designations, the classification of the nonattainment area must be specified, i.e., transitional, marginal, moderate, serious, severe, or extreme.

(4) *Boiler design capacity.* A measure of the size of a boiler, based on the reported maximum continuous steam flow. Capacity is calculated in units of MMBtu/hr.

(5) *Control device type.* The name of the type of control device (e.g., wet scrubber, flaring, or process change).

(6) *Control efficiency.* The emissions reduction efficiency of a primary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(7) *Day/week in operations.* Days per week that the emitting process operates.

(8) *Emission factor.* Ratio relating emissions of a specific pollutant to an activity or material throughput level.

(9) *Exit gas flow rate.* Numeric value of stack gas flow rate.

(10) *Exit gas temperature.* Numeric value of an exit gas stream temperature.

(11) *Exit gas velocity.* Numeric value of an exit gas stream velocity.

(12) *Fall throughput (%).* Portion of throughput for the 3 fall months (September, October, November). This represents the expression of annual activity information on the basis of four seasons, typically spring, summer, fall, and winter. It can be represented either as a percentage of the annual activity (e.g., production in summer is 40 percent of the year's production), or in terms of the units of the activity (e.g., out of 600 units produced, spring = 150 units, summer = 250 units, fall = 150 units, and winter = 50 units).

(13) *Federal ID code (plant).* Unique codes for a plant or facility, containing one or more pollutant-emitting sources.

(14) *Federal ID code (point).* Unique codes for the point of generation of emissions, typically a physical piece of equipment.

(15) *Federal ID code (stack number).* Unique codes for the point where emissions from one or more processes are released into the atmosphere.

(16) *Federal Information Placement System (FIPS).* The system of unique numeric codes developed by the government to identify States, counties, towns, and townships for the entire United States, Puerto Rico, and Guam.

(17) *Heat content.* The thermal heat energy content of a solid, liquid, or gaseous fuel. Fuel heat content is typically expressed in units of Btu/lb of fuel, Btu/gal of fuel, joules/kg of fuel, etc.

(18) *Hr/day in operations.* Hours per day that the emitting process operates.

(19) *Maximum design rate.* Maximum fuel use rate based on the equipment's or process' physical size or operational capabilities.

(20) *Maximum nameplate capacity.* A measure of the size of a generator which is put on the unit's nameplate by the manufacturer. The data element is reported in megawatts (MW) or kilowatts (KW).

(21) *Mobile source.* A motor vehicle, nonroad engine or nonroad vehicle, where:

(i) *Motor vehicle* means any self-propelled vehicle designed for transporting persons or property on a street or highway;

(ii) *Nonroad engine* means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 111 or section 202 of the CAA;

(iii) *Nonroad vehicle* means a vehicle that is powered by a nonroad engine and that is not a motor vehicle or a vehicle used solely for competition.

(22) *Ozone season.* The period May 1 through September 30 of a year.

(23) *Physical address.* Street address of facility.

(24) *Point source.* A non-mobile source which emits 100 tons of NO_X or more per year unless the State designates as a point source a non-mobile source emitting at a specified level lower than 100 tons of NO_X per year. A non-mobile source which emits less NO_X per year than the point source threshold is an area source.

(25) *Pollutant code.* A unique code for each reported pollutant that has been assigned in the EIIP Data Model. Character names are used for criteria pollutants, while Chemical Abstracts Service (CAS) numbers are used for all other pollutants. Some States may be using storage and retrieval of aerometric data (SAROAD) codes for pollutants, but these should be able to be mapped to the EIIP Data Model pollutant codes.

(26) *Process rate/throughput.* A measurable factor or parameter that is directly or indirectly related to the emissions of an air pollution source. Depending on the type of source category, activity information may refer to the amount of fuel combusted, the amount of a raw material processed, the amount of a product that is manufactured, the amount of a material that is handled or processed, population, employment, number of units, or miles traveled. Activity information is typically the value that is multiplied against an emission factor to generate an emissions estimate.

(27) *SCC. Source category code.* A process-level code that describes the equipment or operation emitting pollutants.

(28) *Secondary control efficiency (%).* The emissions reductions efficiency of a secondary control device, which shows the amount of reductions of a particular pollutant from a process' emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.

(29) *SIC.* Standard Industrial Classification code. U.S. Department of Commerce's categorization of businesses by their products or services.

(30) *Site name.* The name of the facility.

(31) *Spring throughput (%).* Portion of throughput or activity for the 3 spring months (March, April, May). See the definition of Fall Throughput.

(32) *Stack diameter.* Stack physical diameter.

(33) *Stack height.* Stack physical height above the surrounding terrain.

(34) *Start date (inventory year).* The calendar year that the emissions estimates were calculated for and are applicable to.

(35) *Start time (hour).* Start time (if available) that was applicable and used for calculations of emissions estimates.

(36) *Summer throughput (%).* Portion of throughput or activity for the 3 summer months (June, July, August). See the definition of Fall Throughput.

(37) *Summer work weekday emissions.* Average day's emissions for a typical day.

(38) *VMT by Roadway Class.* This is an expression of vehicle activity that is used with emission factors. The emission factors are usually expressed in terms of grams per mile of travel. Since VMT does not directly correlate to emissions that occur while the vehicle is not moving, these non-moving emissions are incorporated into EPA's MOBILE model emission factors.

(39) *Week/year in operation.* Weeks per year that the emitting process operates.

(40) *Work Weekday.* Any day of the week except Saturday or Sunday.

(41) *X coordinate (latitude).* East-west geographic coordinate of an object.

(42) *Y coordinate (longitude).* North-south geographic coordinate of an object.

PART 72—PERMITS REGULATION

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

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

2. Section 72.2 is amended by revising the definition for ''excepted monitoring system,'' and adding new definitions in alphabetical order for ''low mass emissions unit'', ''maximum potential hourly heat input'', ''maximum rated hourly heat input,'' and ''ozone season'' to read as follows:

§ 72.2 Definitions.

* * * * *

Excepted monitoring system means a monitoring system that follows the procedures and requirements of § 75.19 of this chapter or of appendix D or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Low mass emissions unit means an affected unit that is a gas-fired or oil-fired unit, burns only natural gas or fuel oil and qualifies under § 75.19 of this chapter.

* * * * *

Maximum potential hourly heat input means an hourly heat input used for reporting purposes when a unit lacks certified monitors to report heat input. If the unit intends to use appendix D of part 75 of this chapter to report heat input, this value should be calculated, in accordance with part 75 of this chapter, using the maximum fuel flow rate and the maximum gross calorific value. If the unit intends to use a flow monitor and a diluent gas monitor, this value should be reported, in accordance with part 75 of this chapter, using the maximum potential flow rate and either the maximum carbon dioxide concentration (in percent CO_2) or the minimum oxygen concentration (in percent O_2).

* * * * *

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

* * * * *

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

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

3. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651k, 7651 and note.

4. Section 75.1 is amended by revising paragraph (a) to read as follows:

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401–7671q as amended by Public Law 101–549 (November 15, 1990). In addition, this part sets forth provisions for the monitoring, recordkeeping, and reporting of NO_X mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

* * * * *

5. Section 75.2 is amended by revising paragraph (a) and adding a new paragraph (c) to read as follows:

§ 75.2 Applicability.

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_X.

* * * * *

(c) The provisions of this part apply to sources subject to a State or federal NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.

6. Section 75.4 is amended by revising paragraph (a) introductory text to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable State or federal NO_X mass emission reduction program, to the extent these provisions are adopted as requirements under such a program. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO_2, NO_X, CO_2, opacity, and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (h) of this section):

* * * * *

7. Section 75.6 is amended by adding paragraph (f) to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070.

(1) American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; for § 75.19.

(2) Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992), for § 75.19.

8. Section 75.11 is amended by removing the period at the end of paragraph (d)(2) and replacing it with ‘‘; or’’ and adding paragraph (d)(3), to read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).

* * * * *

(d) * * *

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

* * * * *

9. Section 75.12 is amended by revising the section heading, by redesignating paragraph (d) as paragraph (e), and by adding new paragraph (d) to read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate (NO_X and diluent gas monitors).

* * * * *

(d) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (a) and (c) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system;

(2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions, if applicable under § 75.19(a) and (b).

* * * * *

10. Section 75.13 is amended by adding paragraph (d) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

* * * * *

(d) *Determination of CO_2 mass emissions from low mass emissions units.* The owner or operator of a unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_2 mass emissions, if applicable under § 75.19(a) and (b).

* * * * *

11. Section 75.17 is amended by adding introductory text before paragraph (a) to read as follows:

§ 75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_X emission rate.

Notwithstanding the provisions of paragraphs (a), (b), and (c) of this section, the owner or operator of an affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_X mass emission reduction program must also meet the provisions for monitoring NO_X emission rate in §§ 75.71 and 75.72.

* * * * *

12. Section 75.19 is added to subpart B to read as follows:

§ 75.19 Optional SO_2, NO_X, and CO_2 emissions calculation for low mass emissions units.

(a) *Applicability.* (1) Consistent with the requirements of paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_X, SO_2, and CO_2 mass emissions from a low mass emissions unit.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired unit, that burns only natural gas or fuel oil and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits no more than 25 tons of SO_2 annually and no more than 50 tons of NO_X annually; and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emission unit continues to emit no more than 25 tons of SO_2 annually and no more than 50 tons of NO_X annually.

(ii) Any qualifying unit must start using the low mass emissions excepted methodology in the first hour in which the unit operates in a calendar year. Notwithstanding, the earliest date for which a unit that meets the eligibility requirements of this section may begin to use this methodology is January 1, 2000.

(2) A unit may initially qualify as a low mass emissions unit only under the following circumstances:

(i) If the designated representative submits a certification application to use the low mass emissions excepted methodology and the Administrator certifies the use of such methodology. The certification application must contain:

(A) Actual SO_2 and NO_X mass emissions data for each of the three calendar years prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO_2 and less than 50 tons of NO_X annually; and

(B) Calculated SO_2 and NO_X mass emissions, for each of the three calendar years prior to the calendar year in which the certification application is submitted, demonstrating to the satisfaction of the Administrator that the unit emits less than 25 tons of SO_2 and less than 50 tons of NO_X annually. The calculated emissions for each year shall be determined using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO_2, NO_X, and CO_2 emission rate from paragraph (c)(1)(i) of this section for SO_2, paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_X and paragraph (c)(1)(iii) of this section for CO_2; or

(ii) When the three full years of actual, historical SO_2 and NO_X mass emissions data required under paragraph (a)(2)(i) of this section are not available, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of historical SO_2 and NO_X mass emissions data and projected SO_2 and NO_X mass emissions, totaling three years. Historical data must be used for any years in which historical data exists and projected data should be used for any remaining future years needed to provide capacity factor data for three consecutive calender years. For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for unit that commenced operation after January 1, 1997, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than 25 tons of SO_2 and less than 50 tons of NO_X annually. Projected emissions shall be calculated using either the default emission rates in tables 1,2 and 3 of this section, or for NO_X emission rate a fuel-and-unit-specific NO_X emission rate determined in accordance with the testing procedures in paragraph (c)(1)(iv) of this section, in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section.

(b) *On-going qualification and disqualification.* (1) Once a low mass emission unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit less than 25 tons of SO_2 annually and less than 50 tons of NO_X annually. The calculation methodology used for the annual demonstration shall be the same methodology, from paragraph (c) of this section, by which the unit initially qualified to use the low mass emissions excepted methodology.

(2) If any low mass emission unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative year-to-date emissions for the unit exceed 25 tons of SO_2 or 50 tons of NO_X in any calendar quarter of any calendar year, then;

(i) The low mass emission unit shall be disqualified from using the low mass emissions excepted methodology as of the end of the second calendar quarter following such quarter in which either the 25 ton limit for SO_2 or the 50 ton limit for NO_X was exceeded; and

(ii) The owner or operator of the low mass emission unit shall have two calendar quarters from the end of the quarter in which the unit exceeded the 25 ton limit for SO_2 or the 50 ton limit for NO_X to install, certify, and report SO_2, NO_X, and CO_2 emissions from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13.

(3) If a low mass emission unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology (e.g. natural gas or fuel oil) is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install, certify, and report SO_2, NO_X, and CO_2 from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13 prior to a change to such fuel. The owner or operator must notify the Administrator in the case where a unit switches fuels without previously having installed and certified a SO_2, NO_X and CO_2 monitoring system meeting the requirements of §§ 75.11, 75.12, and 75.13.

(4) If a unit commencing operation after January 1, 1997 initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use a low mass emissions methodology for the unit, he or she must:

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a unit subject to a NO_X mass reduction program;

(ii) Use these records to determine the cumulative heat input and SO_2, NO_X, and CO_2 mass emissions in order to continue to qualify as a low mass emission unit; and

(iii) Determine the cumulative SO_2 and NO_X mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in tables 1, 2 and 3 of this section or use the fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section. The Administrator will not count SO_2 mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under § 75.4 against SO_2 allowances to be held in the unit account.

(5) A low mass emission unit that has been disqualified from using the low mass emissions excepted methodology may subsequently qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section, provided that if such unit qualified under paragraph (a)(2)(ii) of this section, the unit may subsequently qualify again only if the unit meets the requirements of paragraph (a)(2)(i) of this section.

(c) *Low mass emissions excepted methodology, calculations, and values.*

(1) *Determination of SO_2, NO_X, and CO_2 emission rates.*

(i) Use Table 1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section.

(ii) Use either the appropriate NO_X emission factor from Table 2 of this section, or a fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_X mass emissions under this section.

(iii) Use Table 3 of this section to determine the appropriate CO_2 emission rate for use in calculating hourly CO_2 mass emissions under this section.

(iv) In lieu of using the default NO_X emission rate from Table 2 of this section, the owner or operator may, for each fuel combusted by a low mass emission unit, determine a fuel-and-unit-specific NO_X emission rate for the purpose of calculating NO_X mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. If this option is chosen, the following procedures shall be used.

(A) Except as otherwise provided in paragraphs (c)(1)(iv)(F) and (G) of this paragraph, determine a fuel-and-unit-specific NO_X emission rate by conducting a four load NO_X emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:

(*1*) Do not measure the heat input as required under 2.1.3 of appendix E to this part.

(*2*) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

(B) Representative appendix E testing may be done on low mass emission units in a group of identical units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.

(*1*) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of modifications (e.g., have the same controls installed, the same types of burners and have undergone major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ±50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.

(*2*) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table 4 of this section.

(*3*) If there are only two low mass emission units in the group of identical units, the results of the representative testing under paragraph (c)(1)(iv)(B)(1) of this section may be used to establish the fuel-and-unit-specific NO_X emission rate(s) for the units. However, if there are more than two low mass emission units in the group, the testing must confirm that the units are identical by meeting the following criteria. The results of the representative testing may only be used to establish the fuel-and-unit-specific NO_X emission rate(s) for such units if the following criteria are met:

(*i*) at each of the four load levels tested, the NO_X emission rate for each tested low mass emission unit does not differ by more than ±10% from the average of the NO_X emission rates for all units tested, or;

(*ii*) if the average NO_X emission rate of all low mass emission units tested at all four load levels is less than 0.20 lb/mmBtu, an alternative criteria of ±0.020 lb/mmBtu may be use in lieu of the 10% criteria. Units must all be within +0.020 lb/mmBtu of the average from the test to be considered identical units under this section.

(*4*) If the acceptance criteria in paragaph (c)(1)(iv)(B)(3) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.

(*5*) Fuel and unit specific NO_X emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.

(C) Based on the results of the appendix E testing, determine the fuel-and-unit-specific NO_X emission rate as follows:

(*1*) For an individual low mass emission unit with no NO_X emissions controls of any kind, the highest NO_X emission rate obtained for a particular type of fuel in the appendix E test multiplied by 1.15 shall be the fuel-and-unit-specific NO_X emission rate, for that type of fuel.

(*2*) For a group of low mass emission units sharing a common fuel supply with no NO_X controls of any kind on any of the units, the highest NO_X emission rate obtained for a particular type of fuel in all of the appendix E tests of all units in the group of units sharing a common fuel supply multiplied by 1.15 shall be the fuel-and-unit-specific NO_X emission rate for each unit in the group, for that type of fuel.

(*3*) For a group of identical low mass emission units which perform representative testing according to paragraph (c)(1)(iv)(B) of this section with no NO_X controls of any kind on any of the units, the fuel-and-unit-specific NO_X emission rate for all units, for a particular type of fuel, multiplied by 1.15 shall be the highest NO_X

emission rate from any unit tested in the group, for that type of fuel.

(*4*) For an individual low mass emission unit which has NO_X emission controls of any kind, the fuel-and-unit-specific NO_X emission rate for each type of fuel combusted in the unit shall be the higher of:

(*i*) The highest emission rate from the appendix E test for that type of fuel multiplied by 1.15; or

(*ii*) 0.15 lb/mmBtu.

(*5*) For a group of low mass emission units sharing a common fuel supply, one or more of which has NO_X controls of any kind, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units sharing a common fuel supply shall, for a particular type of fuel combusted by the group of units sharing a common fuel supply, shall be the higher of:

(*i*) The highest NO_X emission rate from all appendix E tests of all low mass emission units in the group for that type of fuel multiplied by 1.15; or

(*ii*) 0.15 lb/mmBtu.

(*6*) For a group of identical low mass emission units, which perform representative testing according to paragraph (c)(1)(iv)(B) of this section and have identical NO_X controls, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(*i*) The highest NO_X emission rate from all appendix E tests of all tested low mass emission units in the group of identical units for that type of fuel multiplied by 1.15; or

(*ii*) 0.15 lb/mmBtu.

(D) For each low mass emission unit, each unit in a group of units sharing a common fuel supply, or identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_X emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_X emission rate every five years, unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate. If such changes occur, the fuel-and-unit-specific NO_X emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. If a low mass emission unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_X emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_X emission rate unless such unit also undergoes changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rates.

(E) Each low mass emission unit, each low mass emission unit in a group of units combusting a common fuel, or each low mass emission unit in a group of identical units for which a fuel-and-unit-specific NO_X emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.

(F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_X emission rate(s). However, fuel-and-unit-specific NO_X emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.

(G) Low mass emission units for which at least 3 years of NO_X emission rate continuous emissions monitoring system data and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_X emission rates from the actual data using the following procedure. Separate the actual NO_X emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_X emission rate. Determine the 95th percentile NO_X emission rate for each data set as defined in § 72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_X emission rate, except that for a unit with NO_X emission controls of any kind, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_X emission rate.

(H) For low mass emission units with NO_X emission controls, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_X emission controls are operating properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_X controls are operating properly and to allow the determination of the correct NO_X emission rate as required under paragraph (c)(1)(iv) of this section.

(*1*) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_X emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_X controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to-fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_X emission rate may not be used for that hour.

(*2*) For low mass emission units with other types of NO_X controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_X controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_X emission rates may not be used in that hour.

(2) *Records of operating time, fuel usage, unit output and NO_X emission control operating status.* The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection:

(i) For each low mass emission unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.

(ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type(s) of fuel(s) combusted in the unit during each hour of unit operation.

(iii) For each low mass emission unit using the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit output (in megawatts or thousands of pounds of steam), for the purpose of apportioning heat input to the individual unit operating hours.

(iv) For each low mass emission unit with NO_X emission controls of any kind, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_X controls.

(3) *Heat input.* Hourly, quarterly and annual heat input for a low mass emission unit shall be determined using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.

(i) *Maximum rated hourly heat input method.* (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, the hourly heat input (mmBtu) to a low mass emission unit shall be deemed to equal the maximum rated hourly heat input, as defined in § 72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(B) The quarterly heat input, HI_{qtr}, in mmBtu, shall be determined using Equation LM–1:

$$HI_{qtr} = T_{qtr} \times HI_{hr} \qquad \text{(Eq. LM–1)}$$

Where:

T_{qtr} = Actual number of operating hours in the quarter (hr).

HI_{hr} = Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

(C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.

(ii) *Long term fuel flow heat input method.* The owner or operator may, for the purpose of demonstrating that a low mass emission unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emission unit.

(A) This option may be used for a group of low mass emission units only if:

(*1*) The low mass emission units combust fuel from a common source of supply; and

(*2*) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and

(*3*) All of the units in the group are low mass emission units.

(B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods;

(*1*) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

(*2*) American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under § 75.6); or;

(*3*) A fuel flow meter certified and maintained according to appendix D to this part.

(C) For each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(*1*) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used; or

(*2*) Using the appropriate default gross calorific value listed in Table 5 of this section.

(D) For each type of fuel oil combusted during the quarter, the specific gravity of the oil shall be determined either by:

(*1*) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year shall be used; or

(*2*) Using the appropriate default specific gravity value in Table 5 of this section.

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emission unit or group of low mass emission units sharing a common fuel supply shall be determined using Equation LM–2 for oil and LM–3 for natural gas.

$$HI_{fuel\text{–}qtr} = M_{qtr} \frac{GCV_{max}}{10^6}$$

Eq LM–2 (for fuel oil or diesel fuel)

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly total heat input from oil (mmBtu).

M_{qtr} = Mass of oil consumed during the entire quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb)

GCV_{max} = Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel\text{–}qtr} = Q_g \frac{GCV_{max}}{10^6}$$

Eq LM–3 (for natural gas)

Where:

$HI_{fuel\text{-}qtr}$ = Quarterly heat input from natural gas (mmBtu).

Q_g = Value of natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf).

GCV_g = Gross calorific value of the natural gas combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf)

10^6 = Conversion of Btu to mmBtu.

(F) The quarterly heat input (mmBtu) for all fuels for the quarter, $HI_{qtr\text{-}total}$, shall be the sum of the $HI_{fuel\text{-}qtr}$ values determined using Equations LM–2 and LM–3.

$$HI_{qtr-total} = \sum_{all-fuels} HI_{fuel-qtr}$$

(Eq. LM–4)

(G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input ($HI_{qtr-total}$) values for all calendar quarters in the year to date.

(H) For each low mass emission unit, each low mass emission unit of an identical group of units, or each low mass emission unit in a group of units sharing a common fuel supply, the owner or operator shall determine the quarterly unit output in megawatts or pounds of steam. The quarterly unit output shall be the sum of the hourly unit output values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6.

$$MW_{qtr} = \sum_{all-hours} MW$$

Eq LM–5 (for MW output)

$$ST_{qtr} = \sum_{all-hours} ST$$

Eq LM–6 (for steam output)

Where:

MW_{qtr} = the power produced during all hours of operation during the quarter by the unit (MW)

$ST_{fuel-qtr}$ = the total quarterly steam output produced during all hours of operation during the quarter by the unit (klb)

MW = the power produced during each hour in which the unit operated during the quarter (MW).

ST = the steam output produced during each hour in which the unit operated during the quarter (klb)

(I) For a low mass emission unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of unit operation using either Equation LM–7 or LM–8:

$$HI_{hr} = HI_{qtr-total}\frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM–7 for MW output)

$$HI_{hr} = HI_{qtr-total}\frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM–8 for steam output)

Where:

HI_{hr} = hourly heat input to the unit (mmBtu)

MW_{hr} = hourly output from the unit (MW)

ST_{hr} = hourly steam output from the unit (klb)

(J) For each low mass emission unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, $HI_{qtr-total}$ to each hour of operation using either Equation LM–7a or LM–8a:

$$HI_{hr} = HI_{qtr-total}\frac{MW_{hr}}{\sum_{all-units} MW_{qtr}}$$

(Eq LM–7a for MW output)

$$HI_{hr} = HI_{qtr-total}\frac{ST_{hr}}{\sum_{all-units} ST_{qtr}}$$

(Eq LM–8a for steam output)

Where:

HI_{hr} = hourly heat input to the individual unit (mmBtu)

MW_{hr} = hourly output from the individual unit (MW)

ST_{hr} = hourly steam output from the individual unit (klb)

$\sum_{all-units} MW_{qtr}$ = Sum of the quarterly outputs (from Eq. LM-5) for all units in the group (MW)

$\sum_{all-units} ST_{qtr}$ = Sum of the quarterly steam outputs (from Eq. LM-6) for all units in the group (klb)

(4) *Calculation of SO_2, NO_X and CO_2 mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emission unit meets the requirements of this section, calculate SO_2, NO_X and CO_2 mass emissions in accordance with the following.

(i) *SO_2* mass emissions. (A) The hourly SO_2 mass emissions (lbs) for a low mass emission unit shall be determined using Equation LM–9 and the appropriate fuel-based SO_2 emission factor from Table 1 of this section for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$W_{SO2}=EF_{SO2}\times HI_{hr}$ (Eq. LM–9)

where:

W_{SO2}=Hourly SO_2 mass emissions (lbs).

EF_{SO2}=SO_2 emission factor from Table 1 of this section (lb/mmBtu).

HI_{hr}=Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly SO_2 mass emissions (tons) for the low mass emission unit shall be the sum of all the hourly SO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative SO_2 mass emissions (tons) for the low mass emission unit shall be the sum of the quarterly SO_2 mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii) *NO_X mass emissions.* (A) The hourly NO_X mass emissions for the low mass emission unit (lbs) shall be determined using Equation LM–10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_X emission controls of any kind and for which a fuel-and-unit-specific NO_X emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_X emission controls are operating properly, use the NO_X emission rate from Table 2 of this section for the fuel combusted during the hour with the highest NO_X emission rate.

$W_{NOx}=EF_{NOx}\times HI_{hr}$ (Eq. LM–10)

Where:

WNO_X=Hourly NO_X mass emissions (lbs).

$EFNO_X$=Either the NO_X emission factor from Table 1b of paragraph (c)(1)(ii) of this section of this section or the fuel-and-unit-specific NO_X emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr}=Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph(c)(3)(ii) of this section (mmBtu).

(B) The quarterly NO_X mass emissions (tons) for the low mass emission unit shall be the sum of all of the hourly NO_X mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative NO_X mass emissions (tons) for the low mass emission unit shall be the sum of the