ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 78, and 97

[FRL–7644–7]

RIN 2060–AJ16

Interstate Ozone Transport: Response to Court Decisions on the NO_X SIP Call, NO_X SIP Call Technical Amendments, and Section 126 Rules

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In today's action, EPA is establishing the final full nitrogen oxides (NO_X) budgets for States subject to the NO_X State implementation plan (SIP) Call. This final rule requires States that submitted SIPs to meet the Phase I NO_X SIP Call budgets to submit Phase II SIP revisions as needed to achieve the necessary incremental reductions of NO_X. It also requires Georgia and Missouri to submit SIP revisions meeting the full NO_X SIP Call budgets since they were not required to submit Phase I SIPs. These SIPs are necessary to prohibit specified amounts of emissions of NO_X—one of the precursors to ozone (smog) pollution—for the purposes of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States.

In today's action, we are amending two related final rules we issued under sections 110 and 126 of the Clean Air Act (CAA) related to interstate transport of NO_X. We are responding to the March 3, 2000 decision of the United States Court of Appeals for the District of Columbia Circuit (DC Circuit) in which the Court largely upheld the NO_X SIP Call, but remanded four narrow issues to us for further rulemaking action; the related decision by the DC Circuit on June 8, 2001, concerning the rulemakings providing technical amendments to the NO_X SIP Call in which the Court, among other things, vacated and remanded an issue for further rulemaking; the decision by the DC Circuit on May 15, 2001, concerning the related Section 126 rulemaking in which the Court, among other things, vacated and remanded an issue for further rulemaking; and the related decision by the DC Circuit on August 24, 2001, concerning the Section 126 Rule, in which the Court remanded an issue.

We are also taking final action on modifications that were proposed on June 13, 2001 to the Appeal Procedures and to the Federal NO_X Budget Trading Program. Today's final rule completes action on the June 13, 2001 proposed rule revisions for sources subject to the Federal NO_X Budget Trading Program under the Section 126 final rule.

The specific issues addressed in this action are described below under **SUPPLEMENTARY INFORMATION.**

DATES: This rule is effective June 21, 2004.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to Jan King, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, C539–02, Research Triangle Park, NC, 27711, telephone (919) 541–5665, e-mail *king.jan@epa.gov.* Technical questions concerning electric generating units (EGUs) should be directed to Kevin Culligan, Office of Atmospheric Programs, Clean Air Markets Division, (6204M), 1200 Pennsylvania Ave., NW., Washington, DC 20460, telephone (202) 564–9172, e-mail *culligan.kevin@epa.gov*; technical questions concerning stationary internal combustion (IC) engines should be directed to Doug Grano, Office of Air Quality Planning and Standards, C539–02, Research Triangle Park, North Carolina 27711, telephone (919) 541–3292, e-mail *grano.doug@epa.gov;* legal questions should be directed to Winifred Okoye, Office of General Counsel, (2344A), 1200 Pennsylvania Ave., NW., Washington, DC 20460, telephone (202) 564–5446, e-mail *okoye.winifred@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Today's action addresses the issues remanded or vacated by the DC Circuit in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir., 2000), *cert. denied,* 121 S. Ct. 1225, 149 L. ED. 135 (2001), which concerned the NO_X SIP Call (the "SIP Call case''); *Appalachian Power* v. *EPA,* 251 F.3d 1026 (DC Cir. 2001), which concerned the technical amendments rulemakings for the NO_X SIP Call (the "Technical Amendments case''); and *Appalachian Power* v. *EPA,* 249 F.3d 1042 (DC Cir. 2001).

Today's action establishes the second phase or Phase II of the NO_X SIP Call by:

(1) Finalizing the definition of EGU as applied to certain small cogeneration units,

(2) Setting the control levels for stationary IC engines,

(3) Excluding portions of Georgia, Missouri, Alabama and Michigan from the NO_X SIP Call,

(4) Revising statewide emissions budgets in the NO_X SIP Call to reflect the disposition of the first three issues above,

(5) Setting a SIP submittal date,

(6) Setting the compliance date for implementation of control measures, and

(7) Excluding Wisconsin from NO_X SIP Call requirements.

For more detailed discussions of the issues addressed in this action, *see* section II below.

Ground-level ozone has long been recognized to affect public health. Ozone induces health effects, including decreased lung function (primarily in children active outdoors), increased respiratory symptoms (particularly in highly sensitive individuals), increased hospital admissions and emergency room visits for respiratory causes (among children and adults with pre-existing respiratory disease such as asthma), increased inflammation of the lungs, and possible long-term damage to the lungs. Each year, ground-level ozone is also responsible for crop yield losses. Ozone also causes noticeable foliar damage in many crops, trees, and ornamental plants (*i.e.*, grass, flowers, shrubs, and trees) and causes reduced growth in plants. Studies indicate that current ambient levels of ozone are responsible for damage to forests and ecosystems (including habitat for native animal species).

B. How Can I Get Copies of Related Information?

1. *Docket.* EPA has established an official public docket for this action under Docket ID No. OAR–2001–0008; it has also been incorporated by reference in the docket for the Section 126 Rule under Docket ID No. OAR–2001–0009. The official public docket consists of the documents specifically referenced in this action, any public comments received, and other information related to this action. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Documents in the official public docket are listed in the index list in EPA's electronic public docket and comment system, EDOCKET. Documents may be available either electronically or in hard copy. Electronic documents may be viewed through EDOCKET. Hard copy documents may be viewed at the Air Docket in the EPA Docket Center, (EPA/DC) EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone

number for the Air Docket is (202) 566–1742; fax (202) 566–1741. A reasonable fee may be charged for copying.

2. *Electronic Access.* You may access this Federal Register document electronically through the EPA Internet under the "Federal Register'' listings at *http://www.epa.gov/fedrgstr/* or the federal wide eRulemaking site at *http://www.regulations.gov.*

An electronic version of the public docket is available through EDOCKET. You may use EDOCKET at *http://www.epa.gov/edocket/* to view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Publicly available docket materials that are not available electronically may be viewed at the docket facility identified in Unit I.B. Once in the system, select "search,'' then key in the appropriate docket identification number.

Public Hearing

We held a public hearing in Washington, DC on March 15, 2002. Four people presented comments at the hearing. The public also had an opportunity to submit written testimony within approximately 45 days after the hearing date.

Outline

I. Background

A. What Was Contained in the NO_X SIP Call?

By notice dated October 27, 1998 (63 FR 57356), we took final action to prohibit specified amounts of emissions of one of the main precursors of ground-level ozone, NO_X, in order to reduce ozone transport across State boundaries in the eastern half of the United States. Based on extensive air quality modeling and analyses, we found that sources in 22 States and the District of Columbia (DC) (23 States) emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour ozone national ambient air quality standards (NAAQS) in downwind States. We set forth requirements for each of the affected upwind States to submit SIP revisions prohibiting those amounts of NO_X emissions which significantly contribute to downwind air quality problems. We established statewide NO_X emissions budgets for the affected States. The budgets were calculated by assuming the emissions reductions that would be achieved by applying available, highly cost-effective controls to source categories of NO_X. States have the flexibility to adopt the appropriate mix of controls for their State to meet the NO_X emissions reductions requirements of the NO_X SIP Call. A number of parties, including certain States as well as industry and labor groups, challenged our NO_X SIP Call Rule.

Independently, we also found that sources and emitting activities in 22 States and the District of Columbia emit NO_X in amounts that significantly contribute to nonattainment of the 8-hour ozone NAAQS. In response to the court decisions, on September 18, 2000 (65 FR 56245), we stayed the findings in the NO_X SIP Call based on the 8-hour ozone NAAQS. However, we are evaluating the process for lifting the stay in light of recent EPA actions on the 8-hour ozone standard.

B. What Were the Court Decisions on the NO_X SIP Call?

1. What Was the Decision of the Court on the 8-Hour Ozone NAAQS?

On May 14, 1999, the DC Circuit issued an opinion which, in relevant parts, questioned the constitutionality of the CAA as applied by EPA in its 1997 revision of the ozone NAAQS. *See American Trucking Ass'n* v. *EPA,* 175

F.3d 1027 (DC Cir. 1999). The Court's ruling curtailed our ability to require States to comply with a more stringent ozone NAAQS.

On October 29, 1999, the DC Circuit granted in part and denied in part our rehearing request. *American Trucking Ass'n* v. *EPA,* 194 F.3d 4 (DC Cir. 1999). In May 2000, the Supreme Court granted our petition and certain petitioners' cross-petitions of certiorari. On February 27, 2001, the Supreme Court handed down its decision in *Whitman* v. *American Trucking Association,* 531 U.S. 457 (2001). In vacating the DC Circuit's holding on the point, the Supreme Court held that the CAA was not unconstitutional in its delegation of authority for us to promulgate a revised ozone NAAQS. The case was remanded to the DC Circuit to consider challenges to the revised ozone NAAQS on other grounds.

2. What Effect Did the Court Decision Have on the 8-Hour Portion of the NO_X SIP Call?

The litigation created uncertainty with respect to our ability to rely upon the 8-hour ozone standards as an alternative basis for the NO_X SIP Call. As a result, we stayed indefinitely the findings of significant contribution based on the 8-hour standard, pending further developments in the NAAQS litigation (65 FR 56245, September 18, 2000). Because the NO_X SIP Call Rule was based independently on the 1-hour standards, a stay of the findings based on the 8-hour standards had no effect on the remedy required by the 1998 NO_X SIP Call. That is, the stay does not affect our findings based on the 1-hour standards.

3. What Was the DC Circuit Decision on the Stay of the SIP Submittal Schedule for the NO_X SIP Call?

The NO_X SIP Call Rule required States to submit SIP revisions by September 30, 1999. State petitioners challenging the NO_X SIP Call filed a motion requesting the Court to stay the submission schedule until April 27, 2000. In response, the DC Circuit issued a stay of the SIP submission deadline pending further order of the Court. *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000) (May 25, 1999 order granting stay in part).

4. What Was the Court's Decision on the NO_X SIP Call?

On March 3, 2000, the DC Circuit issued its decision on the NO_X SIP Call, ruling in our favor on the issues that affected the rulemaking as a whole, but ruling against us on several issues. *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000). The Court's decision in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000) concerns only the 1-hour basis for the NO_X SIP Call, and not the 8-hour basis. The requirements of the NO_X SIP Call, including the findings of significant contribution by the 23 States, the emissions reductions that must be achieved, and the requirement for States to submit SIPs meeting statewide NO_X emissions reductions requirements, are fully and independently supported by our findings under the 1-hour NAAQS alone. The Court denied petitioners' requests for rehearing or rehearing *en banc* on July 22, 2000. Specifically, the Court found in our favor on the following claims:

(1) We could call for the SIP revisions without convening a transport commission;

(2) We undertook a sufficiently State-specific determination of ozone contribution;

(3) We did not unlawfully override past precedent regarding "significant'' contribution;

(4) Our consideration of the cost of NO_X emissions reductions as part of the determination of significant contribution is consistent with the statute and judicial precedent;

(5) Our scheme of uniform emissions reductions requirements is reasonable;

(6) Our interpretation of CAA section 110(a)(2)(D)(i)(I) does not violate the nondelegation doctrine;

(7) We did not intrude on the statutory rights of States to fashion their SIPs;

(8) We properly included South Carolina in the NO_X SIP Call; and

(9) We did not violate the Regulatory Flexibility Act (RFA).

However, the Court ruled against us on four specific issues. Specifically, the Court:

(1) Remanded and vacated the inclusion of Wisconsin because emissions from Wisconsin did not show a significant contribution to downwind nonattainment of the NAAQS;

(2) Remanded and vacated the inclusion of Georgia and Missouri in light of the Ozone Transport Assessment Group (OTAG) conclusions that emissions from coarse grid portions did not merit controls;

(3) Held that we failed to provide adequate notice of the change in the definition of EGU as applied to cogeneration units that supply electricity to a utility power distribution system for sale in amounts of either one-third or less of their potential electrical output capacity or 25 megawatts or less per year (small cogeneration units); and

(4) Held that we failed to provide adequate notice of the change in control level assumed for large stationary IC engines.

The Court remanded the last two matters for further rulemaking.

5. How Did the Court Respond To Our Request To Lift the Stay of the 1-Hour SIP Submission Schedule?

On April 11, 2000, we filed a motion with the Court to lift the stay of the SIP submission date. We requested that the Court lift the stay as of April 27, 2000. We recognized, however, that at the time the stay was issued, States had approximately 4 months (128 days) remaining to submit SIPs. Therefore, our motion to lift the stay indicated that we would allow States until September 1, 2000 to submit SIPs addressing the NO_X SIP Call and provided that States could submit only those portions of the NO_X SIP Call upheld by the Court (Phase I SIPs). The existing record in the NO_X SIP Call rulemaking provides a breakdown of the data on which the original budgets were developed sufficient to allow States to develop Phase I SIPs. However, we reviewed the record and for the convenience of the States and in letters to the State Governors and State Air Directors, dated April 11, 2000, we identified an adjusted Phase I NO_X budget for each State for which the NO_X SIP Call applies.

On June 22, 2000, the Court granted our request in part. The Court ordered that we allow the States 128 days from the June 22, 2000 date of the order to submit their SIPs. Therefore, SIPs in response to the NO_X SIP Call were due October 30, 2000.[1]

In our motion to lift the stay, we informed the Court that the Agency asked 19 States and the District of Columbia, in letters to the Governors dated April 11, 2000, to submit SIPs subject to the Court's response to our motion to lift the stay. The 19 States are: Alabama, Connecticut, Delaware, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia and West Virginia. Rather than submit a SIP that fully met the NO_X SIP Call, we allowed these 19 States and the District of Columbia to submit SIPs that cover all of the NO_X SIP Call requirements except for a small part of the EGU portion and large IC engine portions of the budget. We refer to these partial plans that addressed the portion of the rule unaffected by the Court's remand as

[1] October 30, 2000 was the first business day following expiration of the 128-day period.

the "Phase I'' SIPs.[2] Because the NO_X SIP Call was vacated with respect to Georgia, Missouri, and Wisconsin, those States were not obligated to submit any SIPs by October 30, 2000. The SIPs that cover the portion of the rule affected by the Court decision—and the subject of today's action—are termed, the "Phase II'' SIPs.

6. What Was the Court's Order for the Compliance Date?

In response to a motion filed by the industry/labor petitioners, on August 30, 2000, the DC Circuit ordered that the court order filed on June 22, 2000, be amended to extend the deadline for full implementation of the NO_X SIP Call from May 1, 2003 to May 31, 2004. This extension was calculated in the same manner used by the Court in extending the deadline for SIP submissions, so that sources in States subject to the NO_X SIP Call would have 1,309 days for implementing the SIP as provided in the original NO_X SIP Call.

C. What Was Contained in the Section 126 Rule?

We have also addressed interstate NO_X transport in a final rule (Section 126 Rule) that responds to petitions submitted by eight Northeast States under section 126 of the CAA (65 FR 2674, January 18, 2000)(the Section 126 Rule). In this rule, we made findings that 392 sources in 12 States and the District of Columbia are significantly contributing to 1-hour ozone nonattainment problems in the petitioning States of Connecticut, Massachusetts, New York, and Pennsylvania. The upwind States with sources affected by the Section 126 Rule are: Delaware, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia.[3] The types of sources affected are large EGUs [4] and large industrial boilers and turbines (non-EGUs). The rule established Federal NO_X emissions limits for the affected sources and set a May 1, 2003 compliance date.[5] We promulgated a NO_X cap and trade program as the control remedy. All of the sources affected by this Section 126 Rule are located in States that are subject to the NO_X SIP Call.

The Section 126 Rule includes a provision to coordinate the Section 126 Rule with State actions under the NO_X SIP Call. This provision automatically withdraws the Section 126 findings and control requirements for sources in a State if the State submits, and we give final approval to, a SIP revision meeting the full NO_X SIP Call requirements, including the originally promulgated May 1, 2003 compliance deadline [40 CFR 52.34(i)]. The Court changed the NO_X SIP Call compliance deadline to May 31, 2004 after we had promulgated and justified the automatic withdrawal provision based on approval of a SIP with a May 1, 2003 compliance date (64 FR 28274–76, May 25, 1999; 65 FR 2679–2684, January 18, 2000). As described below, as the result of a court decision, the Section 126 Rule was delayed. On April 30, 2002, we published, "Section 126 Rule: Revised Deadlines; Final Rule,'' (67 FR 21522) which reset the compliance date and other related dates, such as the monitoring certification date. The new compliance date is May 31, 2004. This action harmonized the dates in the Section 126 Rule with those in the NO_X SIP Call.

On April 30, 2002, we published a proposal to revise the Section 126 Rule withdrawal provision so that it would continue to function based on the new compliance dates and on a Phase I SIP (67 FR 21522).

1. What Was the DC Circuit Decision on the Section 126 Rule?

On May 15, 2001, a panel of the DC Circuit largely upheld the Section 126 Rule in *Appalachian Power* v. *EPA*, 249 F.3d 1032 (2001). (*Appalachian Power-Section 126*). However, the Court remanded the method for determining growth to the year 2007 in heat input utilization by EGUs. This calculation is important for determining the requirements for EGUs. In addition, the Court vacated and remanded to us the portion of the rule classifying as EGUs small cogeneration units. Although in the *Michigan* decision (concerning the NO_X SIP Call rulemaking), the DC Circuit remanded this issue on the procedural ground of inadequate notice, in the *Appalachian Power-Section 126* decision, the Court vacated and remanded on grounds that we did not justify our classification of small cogeneration units as EGUs. In an order dated August 24, 2001, the DC Circuit, in *Appalachian Power-Section 126 Case*, remanded the Section 126 Rule with regard to the classification of any cogeneration units as EGUs and tolled (suspended) the date for EGUs to implement controls pending our resolution of the EGU growth factor remand.

During the course of the litigation on the Section 126 Rule, individual sources or groups of sources challenged the rule on grounds that our allocations of allowances were improper. We resolved these cases with several of those sources with our agreement to propose a rulemaking revising the allocations.

D. What Were the Technical Amendments Rulemakings?

When we promulgated the NO_X SIP Call Rule, we decided to reopen public comment on the source-specific data used to establish each State's 2007 EGU budget (63 FR 57427, October 28, 1998). We extended this comment period by notice dated December 24, 1998 (63 FR 71220). We indicated that we would entertain requests to correct the 2007 EGU budgets to take into account errors or updates in some of the underlying emissions inventory and certain other specified data.

Following our review of the comments received, we published a rulemaking providing Technical Amendments to, among other things, the 2007 EGU budgets (64 FR 26298, May 14, 1999). In response to additional comments received, we published a second rulemaking, making additional Technical Amendments to the 2007 EGU budgets (65 FR 11222, March 2, 2000). (These two rulemakings may be referred to, together, as the Technical Amendments Rule.) In promulgating the Technical Amendments Rule, we kept intact our method for determining the budgets, including the methods for determining growth to 2007. We simply made adjustments for particular sources concerning whether they were large EGUs or non-EGUs, and adjustments in the appropriate baselines for those sources.

1. What Was the DC Circuit Decision on the Technical Amendments?

On June 8, 2001, the DC Circuit issued its opinion in a case involving the Technical Amendments. *Appalachian Power* v. *EPA*, 251 F.3d 1026 (DC Cir. 2001). (*Appalachian Power-Technical Amendments*). Although largely upholding the Technical Amendments, the court, as in the *Appalachian Power-Section 126* case, remanded the EGU growth factors and vacated and remanded the portion of the rule classifying small cogeneration units as EGUs. In addition, in the *Appalachian*

[2] The Phase I emissions reductions should achieve approximately 90 percent of the total emissions reductions called for by the NO_X SIP Call.

[3] For Indiana, Kentucky, Michigan, and New York, only sources in portions of the State are affected by that rule.

[4] The Section 126 Rule uses the same definition of EGUs that we are finalizing for the NO_X SIP Call in today's action.

[5] As discussed in the next section, on August 24, 2001, the DC Circuit suspended the compliance date for EGUs while we resolved a remanded issue related to EGU growth factors. We published our response to the growth factor issue on May 1, 2002 (67 FR 21868).

Power-Technical Amendments decision, the Court remanded and vacated the budget under the Technical Amendments Rule for Missouri under both the 1-hour and 8-hour ozone NAAQS.

E. What Is the Overview of DC Circuit Remands/Vacaturs?

In summary, the DC Circuit decisions described above revised or remanded/vacated portions of the NO_X SIP Call, Section 126, and Technical Amendments rulemakings as follows:

(1) Remanded the portion of the NO_X SIP Call requirements based on the assumed control level for stationary IC engines;

(2) Delayed the NO_X SIP Call SIP submittal date to October 30, 2000. *Michigan*;

(3) Delayed the date for implementation of the NO_X SIP Call reductions to May 31, 2004. *Michigan*;

(4) Remanded and vacated the inclusion of Wisconsin. *Michigan*;

(5) Remanded and vacated the NO_X SIP Call budgets for Georgia and Missouri under the 1-hour ozone NAAQS. *Michigan*;

(6) Remanded and vacated the NO_X SIP Call budget, as revised by the Technical Amendments, for Missouri, under the 1-hour and 8-hour ozone NAAQS. *Appalachian Power—Technical Amendments*;

(7) Remanded the EGU growth formula. *Appalachian Power—Section 126, Appalachian Power—Technical Amendments*;

(8) Remanded, or remanded and vacated, the classification of small cogeneration units as EGUs. *Michigan, Appalachian Power—Section 126, Appalachian Power—Technical Amendments*; and

(9) Remanded the classification of any cogeneration units as EGUs. *Appalachian Power—Section 126*.

F. What Is Our Process for Addressing the Remands/Vacaturs?

To date, we have responded to these decisions as detailed below:

In letters dated April 11, 2000, to the Governors of the affected States, we advised that the States may submit by October 30, 2000 Phase I SIPs that include a budget allowing more emissions than under the NO_X SIP Call Rule. This budget need not include any reductions from a set of EGUs that we believe includes all of the small cogeneration units or reductions from stationary IC engines. In addition, we advised Wisconsin that it need not submit a NO_X SIP Call SIP revision. Further, we advised Georgia and Missouri that they did not have to submit NO_X SIP Call SIPs at this time. We advised Alabama and Michigan that although the Court upheld the NO_X SIP Call for their entire States, the reasoning of the Court's opinion concerning Georgia and Missouri supported excluding emissions from the coarse-grid portion of their States. We also stated that if they wanted the coarse-grid portion of their States excluded, they could submit a Phase I budget addressing sources in only the fine-grid portion of the State. All States were further advised that the remanded issues would be addressed in a future rulemaking.

Many States did not officially submit complete SIPs as required by October 30, 2000. By notice dated December 26, 2000 (65 FR 81366), we issued findings of failure to submit.[6] All required States have now submitted complete Phase I SIPs and the sanctions clocks have effectively been turned off.

On February 22, 2002, we proposed our response to the court decisions described above, except for the EGU growth remand. Today's action finalizes the second phase or Phase II of the NO_X SIP Call by addressing the remanded and vacated issues as described above. In addition, we are modifying the budgets for Alabama and Michigan based on inclusion of only the fine grid portion of those States. Further, we are excluding Wisconsin from the 1-hour basis of the NO_X SIP Call.

Any additional emissions reductions required as a result of this rulemaking are reflected in the Phase II portion of the State's emissions budget. The emissions reductions required in Phase II are relatively small, representing less than 10 percent of total reductions required by the NO_X SIP Call. Partial State budgets for Georgia and Missouri and the due date for the SIPs meeting the resulting State emissions budgets ("Phase II'' SIPs) are discussed below in sections II.E and II.J, respectively.

Today's rulemaking does not address the EGU growth remand. We responded to that issue in an action entitled, "Response to Court Remand on NO_X SIP Call and Section 126 Rule,'' which was published in the **Federal Register** on May 1, 2002 (67 FR 21868). Our response to the growth remand was challenged in the DC Circuit. All parties filed briefs in May 2003 and oral argument was held on September 15, 2003. The Agency expects a decision by the Court in the January to March 2004 timeframe.

[6] All required States have submitted final SIPs. We have published final approval for 16 States and the District of Columbia. We have published final conditional approvals for two States.

Today's rulemaking does not address NO_X SIP Call or Section 126 Rule issues related to the 8-hour ozone NAAQS. Although we stayed the findings on the NO_X SIP Call based on the 8-hour ozone standard to address a prior remand of the standard by the DC Circuit (65 FR 56245, September 18, 2000), we are now evaluating lifting the stay in light of our recent response to the Court remand. In the meantime, on June 2, 2003 we published a proposed rulemaking for implementation of the 8-hour ozone NAAQS (68 FR 32801).

II. What Is the Scope of This Action?

In this action, we are finalizing specific changes in response to the Court's rulings on the NO_X SIP Call, Section 126, and Technical Amendments rulemakings. Specifically, we are finalizing the following:

(1) Certain aspects of the definitions of EGU and non-EGU. We are addressing the definition of EGU as applied to cogeneration units by finalizing an EGU definition that excludes certain small cogeneration units for purposes of the NO_X SIP Call and Section 126 rulemakings. We are also finalizing a non-EGU definition that includes such cogeneration units. [**Note** that a cogeneration unit may be owned by a utility or a non-utility and is a unit that uses energy sequentially to produce both useful thermal energy (heat or steam) used for industrial, commercial, or heating or cooling purposes; and electricity.]

(2) The control level assumed for large stationary IC engines in the NO_X SIP Call. We proposed a range of possible control levels (82 percent to 91 percent) to the IC engine portion of the budget. We are setting the control limit for large natural gas-fired stationary IC engines in the NO_X SIP Call at 82 percent, and for diesel and dual fuel stationary IC engines at 90 percent.

(3) Partial State budgets for Georgia, Missouri, Alabama, and Michigan in the NO_X SIP Call.

(4) Changes to the statewide NO_X budgets in the NO_X SIP Call to reflect the appropriate increments of emissions reductions that States should be required to achieve with respect to the three remanded issues (discussed above in numbers 1, 2, 3).

(5) The SIP submittal dates for the required States to address the Phase II portion of the budget, and for Georgia and Missouri to submit full SIPs meeting the NO_X SIP Call. We proposed a range of dates 6 months through 1 year from promulgation of this rule, but no later than April 1, 2003. Based on comments and the delay in finalizing

this rule, we are setting a SIP submittal date 1 year from signature of this rule.

(6) The compliance date for all covered sources to meet Phase II of the NO_X SIP Call. We proposed a compliance date of May 31, 2004 (or, if later, the date on which the source commences operation) for all sources except those in Georgia and Missouri. We proposed May 1, 2005 for sources in those States. We are setting the compliance date as May 1, 2007 (or, if later, the date on which the source commences operation) for sources States choose to control under Phase II, including IC engines and sources in Georgia and Missouri. Sources already controlled in an approved Phase I SIP are required to meet the compliance date stipulated in that SIP, including non-Acid Rain EGUs and any cogeneration units that were previously classified as EGUs and, whose classification changed to non-EGUs under today's rule.

(7) The exclusion of Wisconsin from the NO_X SIP Call.

A. How Do We Treat Cogeneration Units and Non-Acid Rain Units?

By way of background, in light of the *Michigan* decision concerning the NO_X SIP Call, we adopted the view that the States should proceed with developing and submitting SIPs (termed "Phase I'' SIPs) reflecting the level of required reductions that was not affected by the Court's ruling. Accordingly, we determined that the Phase I SIPs, under the Court's ruling, by October 30, 2000, should reflect all reductions required under the NO_X SIP Call, except those reductions attributable to parts of the rule that the Court remanded or vacated, such as reductions by small cogeneration units.

At the time, we were uncertain as to which specific units were small cogeneration units and what total emissions were attributable to small cogeneration units. Even so, we were aware that, although most of the EGUs that were subject to the NO_X SIP Call were also subject to the Acid Rain Program, none of the small cogeneration units were subject to the Acid Rain Program. Accordingly, we erred on the side of caution by authorizing States, in their Phase I SIPs, to exclude the required reductions from all non-Acid Rain units.

In the February 22, 2002 proposal, as applied to small cogeneration units, we proposed to retain the EGU definition in the Section 126 Rule and to retain the basic EGU definition used in the NO_X SIP Call Rule with minor, technical revisions to make it consistent with the definition in the Section 126 Rule. In today's action, we are finalizing an EGU definition that excludes certain small cogeneration units. All other cogeneration units and other non-Acid Rain units are EGUs if the other criteria in the EGU definition are met. Further, we are finalizing a non-EGU definition that includes certain small cogeneration units. As a result, we are setting Phase II budgets that include reductions from small cogeneration units and non-Acid Rain EGUs.

However, our review of the SIPs submitted in response to the NO_X SIP Call indicates that the States already included the non-Acid Rain units in their Phase I SIPs as EGUs or non-EGUs.[7] In addition, for today's final rule, with the possible exception of one source, we have not identified any specific small cogeneration units that were originally treated by EPA, and by States in their Phase I SIPs, as EGUs and which now are defined as non-EGUs because, in general, commenters did not provide specific information identifying any such units. The only exception involves one commenter that claimed that its units (located at the Tobaccoville facility) classified as EGUs should be classified as non-EGUs. However, the commenter did not provide sufficient information (*e.g.*, information supporting the maximum design heat input asserted by the commenter) for us to make a final determination regarding the proper classification of the units. Therefore, today's change does not result in any change to the originally finalized SIP Call budgets (which included reductions from both Phase I and Phase II units).

Nevertheless, it is still possible that some cogeneration units that we classified as EGUs are small cogeneration units that should actually be treated as non-EGUs. To the extent any such units are subsequently identified to EPA, we will make any further revisions to the budgets of particular States during the SIP approval process. Similarly, we will consider, during the SIP approval process, the proper classification of the four units at the Tobaccoville facility identified by the commenter discussed above. Because we anticipate that few, if any, existing units treated as EGUs qualify as small cogeneration units, we expect few, if any, such revisions to the budgets will be necessary and that any such revisions that are necessary will be relatively small and will not affect most States.

We are also finalizing certain technical changes to the EGU definition in the NO_X SIP Call to make it consistent with aspects of the definition of EGU used in the Section 126 Rule. In addition, since the EGU definition establishes the dividing line between the EGU and non-EGU categories, the changes to the EGU definition result in corresponding changes to the non-EGU definition in the NO_X SIP Call. In the process of correcting the EGU and non-EGU definitions, we are also finalizing some minor changes to the terminology, and minor corrections of awkward or inconsistent wording and grammatical errors in the applicability provisions.

To begin, we provide a discussion of what preceded today's final decision on the treatment of cogeneration units. Under the NO_X SIP Call, the amount of a State's significant contribution to nonattainment in another State included the amount of highly cost-effective reductions that could be achieved for large EGUs (*i.e.*, EGUs serving generators with nameplate capacity exceeding 25 MWe) and large non-EGUs (non-EGUs with maximum design heat input capacity exceeding 250 mmBtu/hr) in the State. No reductions for small EGUs or small non-EGUs were included. We determined that reductions by large EGUs to 0.15 lb NO_X/mmBtu and by large non-EGUs to 60 percent of uncontrolled emissions are highly cost effective. In developing the States' budgets, we applied definitions of EGU and non-EGU and determined which sources were large EGUs or large non-EGUs.

In its *Michigan* decision, the DC Circuit upheld this approach, but determined that we did not provide sufficient notice and opportunity to comment for one aspect of our definition of EGU and remanded the rule to us for further consideration. Specifically, a petitioner claimed, and the Court agreed, that "EPA did not provide sufficient notice and opportunity for comment on [the] revision'' of the EGU definition to remove the exclusion, from the EGU category, of cogeneration units that supply one-third or less of their potential electrical output capacity, or 25 megawatts (MWe) or less, to any utility power distribution system for sale. *Michigan* v. *EPA*, 213 F.3d at 691–92. (These thresholds are herein referred to as the "one-third potential electrical output capacity/25 MWe criteria;'' cogeneration units that meet such criteria are herein referred to as "small cogeneration units.'') According to the Court, "two months after the

[7] This is based on both a review of the applicability provisions in the NO_X SIP Call SIPs and the budget demonstrations for those SIPs. For more detailed discussion, see section K.1 of today's preamble.

promulgation of the [NO_X SIP Call] rule, EPA redefined an EGU as a unit that serves a 'large' generator (greater than 25 MWe) that sells electricity.'' *Id.* Application of the exclusion for cogeneration units from the definition of EGU would result in treating as non-EGUs those cogeneration units meeting the "one-third potential electrical output capacity/25 MWe'' criteria and treating as EGUs those cogeneration units not meeting these criteria. *See* Brief of Petitioner Council of Industrial Boiler Owners (CIBO) at 4 (submitted in *Michigan*).

The petitioner argued that, under the NO_X SIP Call, we should apply these criteria for excluding cogeneration units from treatment as EGUs. According to the petitioner, the criteria had been established under the regulations implementing new source performance standards (NSPS) and under title IV of the CAA and the regulations implementing the Acid Rain Program under title IV. The petitioner also stated that section 112 of the CAA defines "electricity steam generating unit'' to exclude cogeneration units meeting the same thresholds.

The Court found that, in failing to apply the "one-third potential electrical output capacity/25 MWe'' criteria for cogeneration units, EPA "was departing from the definition of EGUs as used in prior regulatory contexts'' and "was not explicit about the departure from the prior practice until two months after the rule was promulgated.'' *Michigan*, 213 F.3d at 692. Further, the Court found that:

> it is an exaggeration to state that some general "theme'' of the regulatory consequences of deregulation of the utility industry throughout rulemaking meant that EPA's last-minute revision of the definition of EGU should have been anticipated by industrial boilers as a "logical outgrowth'' of EPA's earlier statements.

Id. The Court therefore remanded the rulemaking to us for further consideration of this issue.

In its decisions on the Section 126 Rule and the Technical Amendments Rulemakings, the DC Circuit, after considering the merits of the issue, vacated and remanded our classification of small cogeneration units as EGUs.

Appalachian Power—Section 126 and *Appalachian Power—Technical Amendments.* The Court held that we had failed to justify this classification and to base it on adequate record support comparing the NO_X reduction costs of cogeneration units to those of other EGUs or demonstrating that there is no relevant physical or technological difference between small cogeneration units and other units treated as EGUs. The Court also remanded our classification of any cogeneration units as EGUs.

In response to the Court's decisions, we addressed the cogeneration unit issue in the February 22, 2002 proposed rule. In the proposed rule, we noted that, in prior regulatory programs, we sought to distinguish between utilities (regulated monopolies in the business of producing and selling electricity) and non-utilities (*e.g.*, independent power producers and industrial companies). In order to make this distinction, we applied the "one third potential electrical output capacity/25 MWe sales'' criteria. These criteria were not always applied only to cogeneration units and did not uniformly result in less stringent regulation for units meeting the criteria. In the proposed rule, we stated that, with the development of competitive markets for electricity generation and sale, we believed that these criteria no longer distinguish between units in the business of producing and selling electricity (*i.e.*, EGUs) and non-EGUs. In addition, we explained that there are no relevant differences between the way cogeneration units and non-cogeneration units are built and operated that justify continuing to use these criteria or that affect the general ability of cogeneration units to control NO_X.

In response to the February 22, 2002 proposed rule, most commenters again argued that, under the NO_X SIP Call, we should apply the "one third potential electrical output capacity/25 MWe sales'' criteria to exclude cogeneration units from treatment as EGUs. The comments included arguments that: Classification of small cogeneration units reverses EPA precedent, contradicts Congressional intent, and will discourage new industrial cogeneration; and it is technically and economically more difficult to control NO_X emissions from non-utility units. A few commenters supported treatment of small cogeneration units as EGUs.

Under today's final rulemaking, we are finalizing an EGU definition that excludes certain small cogeneration units and a corresponding non-EGU definition that includes these units. We still maintain that, with the development of competitive markets for electricity generation and sale, the "one third potential electrical output capacity/25 MWe sales'' criteria no longer distinguishes between units in the business of producing and selling electricity (*i.e.*, EGUs) and non-EGUs. We also continue to believe that there are no relevant differences between the way cogeneration units and non-cogeneration units are built and operated that justify continuing to use these criteria or that affect the general ability of cogeneration units to control NO_X. However, at this time, we do not believe we have adequate record information comparing the NO_X reduction costs of all types of industrial cogeneration units to those of other units that are treated as EGUs.

Our discussion below begins with some background on the historical definition of utility unit and the definition of EGU in the NO_X SIP Call and the Section 126 rulemaking. We then discuss today's final rule, including our final decision on the treatment of cogeneration units and the specific revisions to the definition of EGU and corresponding revisions to the definition of non-EGU.

1. What Is the Historical Definition of Utility Unit?

As discussed in the February 22, 2002 proposed rule (67 FR 8402–3), in prior regulatory programs, we have used variations of the "one-third potential electrical output capacity/25 MWe sales'' criteria to distinguish between utilities and non-utilities. The Agency began using these criteria in 1978, in 40 CFR part 60, subpart Da. Subpart Da established NSPS for "electric utility steam generating units'' capable of combusting more than 250 mmBtu/hr of fossil fuel. "Electric utility steam generating unit'' was defined as a unit "constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MWe electrical output to any utility power distribution system for sale'' (40 CFR 60.41a). In that case, the criteria were not used to exempt units entirely from NSPS. Rather, the criteria were used to classify units capable of combusting more than 250 mmBtu/hr of fossil fuel as either "electric utility steam generating units'' subject to the requirements under subpart Da or to classify them as non-utility "steam generating units'' that, depending on the date of construction, continued to be subject to the requirements for "Fossil-Fuel-Fired Steam Generators'' under subpart D or subsequently became subject to the requirements for "Industrial-Commercial-Institutional Steam Generating Units'' under subpart Db. *See* 40 CFR 60.41a (definitions of "steam generating unit'' and "electric utility steam generating unit''), § 60.40b(a) (stating that subpart Db applies to "steam generating units'' with heat input capacity of more than 100 mmBtu/hr), and § 60.40b(e) (stating that "electric steam generating units'' subject to subpart Da are not subject to subpart

Db). Depending on the specific circumstances (*e.g.*, type of equipment and fuel) of the unit involved, some of the emission limits in subpart Db may be the same as or more stringent than those in subpart D or Da.

We explained that we were distinguishing, in subpart Da, between "electric utility steam generating units'' and "industrial boilers'' because "there are significant differences between the economic structure of utilities and the industrial sector'' (44 FR 33580, 33589, June 11, 1979). The "one-third potential electrical output capacity/25 MWe sales'' criteria were used as a proxy for utility vs. industrial/commercial/institutional (*i.e.*, non-utility) ownership of the units; utility-owned units were covered by subpart Da, while non-utility-owned units were covered by subpart D or Db.

A similar type of distinction between utility and non-utility units (using the "one-third potential electrical output capacity/25 MWe sales'' criteria) continued under the CAA Amendments of 1990, in both title IV and section 112 of title I, but was applied only to cogeneration units. Title IV established the Acid Rain Program whose requirements apply to "utility units.'' Section 402(17)(C) excludes a cogeneration unit from the definition of "utility unit'' unless the unit "is constructed for the purpose of supplying, or commences construction after the date of enactment of [title IV] and supplies, more than one-third of its potential electric output capacity and more than 25 MWe electrical output to any utility power distribution system for sale.'' 42 U.S.C. 7651a(17)(C). *See also* 40 CFR 72.6(b)(4). Section 112 of the CAA, which addresses hazardous air pollutants, excludes from the definition of "electric utility steam generating unit'' cogeneration units (but not non-cogeneration units) that meet the "one-third potential electrical output capacity/25 MWe sales'' criteria [42 U.S.C. 7412(a)(8)]. Under section 112, emission limits established by the Administrator for the pollutants listed in section 112(b) apply generally to stationary sources but apply to "electric utility steam generating units'' only if the Administrator makes a specific finding. The Administrator must conduct a study of the "hazards to public health reasonably anticipated to occur'' from emissions from such units and determine if regulation of "electric utility steam generating units'' is "appropriate and necessary.'' 42 U.S.C. 7412(n)(1)(A). In summary, the above-described provisions vary as to both: (1) The application of the "one-third potential electrical output capacity/25 MWe sales'' criteria, which apply to all units in some provisions and only to cogeneration units in other provisions; and (2) the consequences of a unit meeting the criteria, which results in the unit being subject to more stringent regulation under some provisions and less stringent or later regulation under other provisions.

2. What Was the NO_X SIP Call Definition of EGU?

In the NO_X SIP Call rulemaking, we continued the general approach, described above, of distinguishing between units in the electric generation business (here, EGUs) and units in the industrial sector (here, non-EGUs). However, we adopted a different method of defining which units are in the electric generation business by changing the definition of EGU. We defined EGU by applying to all fossil fuel-fired units the methodology described in detail below and did not apply to cogeneration units the "one-third potential electrical output/25 MWe sales'' criteria. Under the methodology applied to all units, after determining the date on which a unit commenced operation (*i.e.*, commenced combusting fuel), we determined whether the unit should be classified as an EGU or a non-EGU by applying the appropriate criteria depending on the commencement of operation date. Then we classified the unit as a large or small EGU or a large or small non-EGU.

Specifically, we noted in a December 24, 1998 supplemental action that the NO_X SIP Call used the following methodology for classifying all units (including cogeneration units) in the States subject to the NO_X SIP Call as EGUs or non-EGUs (63 FR 71220, 71223). We applied this methodology to cogeneration units and not the "one-third potential electrical output capacity/25 MWe sales'' criteria. *Id.*

(a)(i) For units commencing operation before January 1, 1996, we classified as an EGU any unit serving a generator producing any electricity for sale under firm contract to the electric grid. In the December 24, 1998 supplemental action, we did not define the term "electricity for sale under firm contract to the electric grid.'' [8]

(ii) For units commencing operation before January 1, 1996, we classified as a non-EGU any unit not serving a generator producing electricity for sale under firm contract to the grid.

(iii) For units commencing operation on or after January 1, 1996, we classified as an EGU any unit serving a generator producing any amount of electricity for sale, except as provided in paragraph (a)(iv) below.

(iv) For units commencing operation on or after January 1, 1996, we classified as non-EGUs the following: any unit not serving a generator producing electricity for sale; or any unit serving a generator with a nameplate capacity equal to or less than 25 MWe, producing electricity for sale, and with the potential to use 50 percent or less of the usable energy of the unit. In the December 24, 1998 supplemental action, we did not define the term "usable energy.'' [9] (b)(i) For a unit classified as an EGU under paragraph (a)(i) or (a)(iii) above, we then classified it as a small or large EGU. An EGU serving a generator with a nameplate capacity greater than 25 MWe is a large EGU. An EGU serving a generator with a nameplate capacity equal to or less than 25 MWe is a small EGU. In the December 24, 1998 supplemental action, we did not expressly define the term "nameplate capacity.'' [10]

(ii) For a unit classified as a non-EGU under paragraph (a)(ii) or (a)(iv) above, we then classified it as a small or large non-EGU. A non-EGU with a maximum design heat input greater than 250 mmBtu/hour is a large non-EGU. A non-EGU with a maximum design heat input equal to or less than 250 mmBtu/hour is a small non-EGU. But see 63 FR 71224 (explaining procedures used if data on boiler heat input capacity were not available). In the December 24, 1998 supplemental action, we did not expressly

[8] For purposes of the January 18, 2000 Section 126 final rule, we defined "electricity for sale under firm contract to the electric grid'' as where "the capacity involved is intended to be available at all times during the period covered by the guaranteed commitment to deliver, even under adverse conditions'' (65 FR 2694 and 2731). In the February 22, 2002 proposed rule, we proposed to adopt the definition for the term provided in the January 18, 2000 Section 126 final rule. This definition was based on language from the *Glossary of Electric Utility Terms*, Edison Electric Institute, Publication No. 70–40 (definition of "firm'' power). Generally, capacity "under firm contract to the electricity grid'' is included on Energy Information Administration (EIA) form 860A (called EIA form 860 before 1998) or is reported as capacity projected for summer or winter peak periods on EIA form 411 (Item 2.1 or 2.2, line 10).

[9] For purposes of the January 18, 2000 Section 126 final rule, we used the more familiar term "potential electrical output capacity,'' rather than the term "usable energy.'' We defined "potential electrical output'' using the longstanding definition of the latter term as "33 percent of a unit's maximum design heat input'' (65 FR 2694 and 2731). In the February 22, 2002 proposed rule, we proposed to adopt the same term and definition used in the January 18, 2000 Section 126 final rule. "Potential electrical output capacity'' is used, and defined in this way, in part 72 of the Acid Rain Program regulations (40 CFR 72.2 and 40 CFR part 72, appendix D) and in the new source performance standards (40 CFR 60.41a).

[10] In the part 96 model rule in the NO_X SIP Call (63 FR 57356, 57514–38, October 27, 1998), and subsequently for purposes of the January 18, 2000 Section 126 final rule (65 FR 2729 and 2731), we adopted the long-standing definition of "nameplate capacity'' as "the maximum electrical generating output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the United States Department of Energy standards.'' In the February 22, 2002 proposed rule, we proposed to adopt the same definition used in the January 18, 2000 Section 126 final rule. The term is defined in this way in part 72 of the Acid Rain Program regulations (40 CFR 72.2).

define the term "maximum design heat input."[11] The term is analogous to the term "nameplate capacity'' in that it uses the manufacturer's specifications to categorize the size of the equipment (the generator, in the case of an EGU or the boiler or turbine or combined-cycle system, in the case of non-EGU).[12]

As stated previously, we defined the term "EGU'' by applying to all units, including cogeneration units, the methodology in paragraphs (a)(i) and (a)(iii) above and used the methodology in paragraphs (a)(ii) and (a)(iv) above to define units as non-EGUs. We did not use, for cogeneration units, the "one-third potential electrical output capacity/25 MWe sales'' criteria in the cogeneration exclusion. It was the fact that we did not apply these criteria to cogeneration units that petitioners challenged in *Michigan.* As discussed further below, we are adopting essentially these criteria in today's final rule.

3. What Is the Rationale for the Final Rule's Treatment of Cogeneration Units?

a. *Distinction between units in the electric generation business and units in the industrial sector.* Distinguishing between units producing electricity for sale and units producing electricity for internal use or producing steam is a long-standing approach in setting emission limits. In the NO_X SIP Call, the Section 126 Rule, and today's final rule, we continue to take this general approach by setting different emission limits for units producing electricity for sale (EGUs) and units that do not produce electricity for sale (non-EGUs).

We are retaining this general approach for several reasons. First, this is a long-standing approach, and few, if any, commenters in the NO_X SIP Call and Section 126 rulemakings supported abandoning the distinction between units in the electric generation business and units in the industrial sector. Second, after organizing the units into these two categories, we found that there was some difference in the average compliance costs of the two groups. *See* 65 FR 2677, January 18, 2000 (estimating average large EGU control costs as $1,432 per ton in 1990 dollars in 1997 and average large non-EGU costs as $1,589 per ton). Third, this approach tends to result in units that directly compete in the electric generation business having to meet the same emission limit, and that result seems reasonable.

In the May 15, 2001 decision in the Section 126 case, the DC Circuit expressed concern that, under the Section 126 Rule, a cogenerator that produces electricity for sale may be treated as an EGU, a cogenerator that produces electricity for internal use only may be treated as a non-EGU, and thus two units that are "identical physically'' may be subject to different emission reduction requirements. *Appalachian Power,* 249 F.3d at 1062. We note that this issue is not unique to cogeneration units and is inherent in any regulatory program that distinguishes between units in the electric generation business and units that are in the industrial sector and sets different emission limits for the two groups.[13] As previously discussed, we are continuing to use the general approach of distinguishing between units in the electric generation business and units in the industrial sector in the NO_X SIP Call and Section 126 Rule. We recognize that this may result in units that are physically identical being regulated differently based on whether or not electricity—particularly electricity for sale—is produced by the unit. However, before abandoning the long-standing approach of distinguishing between units on this basis—an action that few, if any, commenters in the NO_X SIP Call and Section 126 rulemakings have advocated—we believe that it is prudent to gain experience in operating the trading program under the NO_X SIP Call and Section 126 Rule. We note that we have already begun the process of treating these units similarly because EGUs and non-EGUs will participate in one trading program and will trade the same NO_X allowances. After we have gained experience with the NO_X SIP Call and Section 126 trading program, we intend to consider whether to treat as the same all large boilers, whether they produce electricity or not.

b. *Effect of electricity competition and electric power restructuring on distinction between utilities and non-utilities.* As discussed in the February 22, 2002 proposed rule (*see* 67 FR 8405–06), the increasingly competitive nature of the electric power industry and the significant and increasing participation of non-utilities (*e.g.*, an independent power producer or an industrial company) in competitive electricity markets support similar treatment of utilities and non-utilities. In the proposed rule, we stated that, with these changes in the electric power industry and electricity markets, there is no longer a factual basis for excluding cogeneration units from treatment as EGUs by using the "one-third potential electrical output capacity/25 MWe sales'' criteria.

Many industry commenters argued that EGU should be defined to exclude a cogeneration unit meeting the "one-third potential electrical output capacity/25 MWe sales'' criteria. They raised several issues in support of their argument of not including small cogeneration units in the definition of EGU. First, commenters argued that the classification of cogeneration units as EGUs reversed our precedent in previous regulations and contradicts Congressional intent underlying the CAA. They also argued that new industrial cogeneration, and the potential emissions and energy efficiency benefits that could result, would be discouraged. In addition, commenters maintained that the costs of any NO_X controls for these units would be reflected in the market for the products produced by the industrial company that uses energy from the cogeneration unit and not in the electricity market. Commenters maintained that a manufacturing company can engage in sales of electricity without being in the business of selling electricity. Sometimes such a company exports electricity to the local utility, even though it remains a net importer of electricity over the long-term. Furthermore, commenters argued that we justified our definition on deregulation and have failed to consider the halt on deregulation efforts that California's electricity crisis spurred in other States.

c. *Differences between the design and operation of cogeneration units and*

[11] In the part 96 model rule in the NO_X SIP Call (63 FR 57516) and subsequently for purposes of the January 18, 2000 Section 126 final rule (65 FR 2729), we defined "maximum design heat input'' as "the ability of a unit to combust a stated maximum amount of fuel per hour (in mmBtu/hr) on a steady state basis, as determined by the physical design and physical characteristics of the unit.'' In the February 22, 2002 proposed rule, we proposed to adopt the same definition used in the January 18, 2000 Section 126 final rule.

[12] For example, in establishing the State budgets for large EGUs and large non-EGUs, we identified existing units as being large or small based on nameplate capacity (for EGUs) or maximum design heat input (for non-EGUs), determined each unit's baseline heat input (using 1995 or 1996) and, after calculating total heat input for large EGUs and for large non-EGUs, grew the total amounts out to 2007 using heat input growth rates to account for new units and increased utilization. There was no provision for modifying the budgets to remove a unit initially qualifying as a large EGU or large non-EGU if the unit changed its generating or heat input capacity.

[13] In fact, use of the "one-third potential electrical output capacity/25 MWe sales'' criteria for cogeneration units distinguishes between EGU cogeneration units and non-EGU cogeneration units based on the cogenerator's amount of electricity sales and raises the same issue. Under these criteria, two physically identical cogeneration units could have different emission limits simply because one produces and sells the requisite amount of electricity and the other produces more electricity for internal use and does not sell the requisite amount.

non-cogeneration units. In the February 22, 2002 proposed rule, we stated that there appear to be no physical, operational, or technological differences between cogeneration units producing electricity for sale and non-cogeneration units producing electricity for sale that would prevent cogeneration units classified as EGUs from achieving average NO_X reductions, and incurring average reduction costs, similar to those achieved by non-cogeneration units. We concluded in the proposed rule that there appear to be no such differences that would justify using the "one-third potential electrical output capacity/25 MWe sales'' criteria for classifying cogeneration units as EGUs or non-EGUs, rather than the classification methodology used for all other units. We still believe that there are no relevant differences between the way cogeneration units and non-cogeneration units are built and operated that affect the general ability of cogeneration units to control NO_X. However, at this time, we do not believe we have adequate record support comparing the NO_X reduction costs of all types of industrial cogeneration units to those of other units that are treated as EGUs.

As discussed in the February 22, 2002 proposed rule, cogeneration units under the NO_X SIP Call or the Section 126 Rule operate in two basic configurations.[14] The first is a boiler followed by a steam turbine-generator. In this configuration, steam is generated by a boiler. The steam is first used to power a steam turbine-generator, while the remaining steam is used for an industrial application or for heating and cooling. The boiler that generates the steam used in this manner is designed and operated in essentially the same way as a boiler that generates steam used only to power a steam turbine-generator. Therefore, any controls that could be used on a boiler used to produce only electricity could also be used on a boiler used for cogeneration. In each case, the boiler emits the same amount of NO_X.

The second typical configuration for a cogeneration unit is a gas-fired combined cycle system. Combined cycle system plant refers to a system composed of a gas turbine, heat recovery steam generator, and a steam turbine. Combined cycle units that cogenerate are designed and operated in essentially the same way as combined cycle units that generate only electricity. The waste heat from the gas turbine serves as the heat input (possibly supplemented by a duct burner) to the heat recovery steam generator that is used to power the steam turbine. Both the gas turbine and the steam turbine are connected to generators to produce electricity. The gas turbine generator and the heat recovery steam generator portions can be adapted to supply process steam as well as electricity. These units typically emit at NO_X levels well below 0.15 lbs/mmBtu even without the use of post-combustion controls. Furthermore, selective catalytic reduction (SCR) has been used extensively on combined cycle units that are used for cogeneration and those used for generation of electricity only and results in NO_X emissions at levels well below 0.15 lb/mmBtu. (*See GE Combined-Cycle Product Line and Performance,* GE Power Systems, October 2000, Docket No. OAR–2001–0008, Item No. XII–L–04 at 10–11.)

Both cogeneration configurations identified above are used at utility and non-utility facilities that produce electricity for sale. The steam generated at these facilities is divided between powering a steam turbine and serving process uses or heating and cooling. The cogeneration units with the same configuration at these facilities are almost identical in design, except that a non-utility facility may use more of the steam for process uses or heating and cooling and less for electricity generation.

Further, in comparison to a non-cogeneration system that generates electricity for sale, either type of cogeneration system looks essentially the same as such a non-cogeneration system except for the addition of valves and piping to send the steam for process use or heating and cooling. In both the cogeneration and non-cogeneration systems that generate electricity for sale, all the flue gas (containing the NO_X emissions) exiting the combustion process can be directed through the pollution control devices and then through a stack. Because the cogeneration and non-cogeneration systems are of essentially the same design and the flue gas exits the systems in the same manner, the control of NO_X emissions can be achieved in the same manner. Any post-combustion pollution control device used for NO_X control in either system is located in the same place and operated in the same manner.[15] As discussed in the February 22, 2002 proposed rule and the technical support document,[16] post-combustion NO_X control technologies, *i.e.*, selective non-catalytic reduction (SNCR) and SCR, are available for use on both non-cogeneration and cogeneration units producing electricity for sale. The technical support document and the other documents cited in the proposed rule support the following conclusions:

(1) Selective non-catalytic reduction is a fully commercial technology that uses reagent injected into the boiler above the combustion zone to reduce NO_X to elemental nitrogen and water. Because the NO_X reduction takes place above the combustion zone, boiler type has an insignificant impact on the ability to use SNCR. Selective non-catalytic reduction has been demonstrated on a wide range of boiler types and sizes (including cogeneration units) and on a wide range of fuels (including bio-mass, wood, or combinations of fuels such as bark, paper sludge, and fiber waste). Selective non-catalytic reduction has been used at a wide range of temperatures (*e.g.*, from 1250 degrees F to 2600 degrees F) and has been designed to handle a wide range of load variation (*e.g.*, 33 percent to 100 percent of a unit's maximum continuous rating).

(2) Selective catalytic reduction is a fully commercial technology that uses both ammonia injected after the flue gases exit the boiler or the combustion turbine and catalyst in a reactor to reduce NO_X to elemental nitrogen and water. Because the NO_X reduction takes place in a reactor outside the combustion and heat transfer zones, boiler type has an insignificant impact on the ability to use SCR. The SCR has been demonstrated on a wide range of boiler types and sizes and on combined cycle systems. The SCR has been used at a wide range of temperatures (*e.g.*, 450 degrees F to 1100 degrees F) and

[14] These two configurations are for cogeneration units in topping cycle cogeneration facilities, where energy is used sequentially, first to produce electricity and then to produce thermal energy for process use or heating and cooling. In bottoming cycle cogeneration facilities, energy is used sequentially first to produce thermal energy and then to produce electricity. (*See Cogeneration Applications Considerations,* R.W. Fisk and R.L. VanHousen, GE Power Systems, 1996, Docket No. OAR–2001–0008, Item No. XII–L–04 at 1–2.) The cogeneration units subject to the NO_X SIP Call and the Section 126 Rule are boilers, turbines, or combined cycle systems and so are likely to operate in topping cycle cogeneration facilities.

[15] For examples and discussion of how post-combustion controls apply to cogeneration units, see Docket No. OAR–2001–0008 (Legacy Docket No. A–96–56), Item Nos. XII–L–02; XII–L–03; and XII–L–05 at 10–11 and 13 (Figure 15). In fact, this is also true for boilers that do not serve any generator. Boilers with or without a generator and with or without the capability to cogenerate are of essentially the same design, and the flue gas exits the systems in the same manner. Any post-combustion pollution control device used for NO_X control in either system is located in the same place and operated in the same manner.

[16] "Lack of Relevant Physical or Technological Differences Between Cogeneration Units and Utility Electricity Generating Units,'' September 25, 2000, Docket No. OAR–2001–0008, Item No. XII–K–47.

has been designed to handle a wide range of load variation.

In the February 22, 2002 proposed rulemaking, we requested comment on, and specific information supporting or contradicting, our conclusions that there are no relevant physical, operational, or technological differences and no significant difference in average control retrofit cost for cogeneration versus non-cogeneration units producing electricity for sale. In response to the proposed rule, commenters raised concerns that it is technically and economically more difficult to control NO_X in industrial cogeneration units than in non-utility units because they are smaller sized than utility boilers, fire multiple fuels and often co-fire two or more fuels, operate in a load-following mode, have lower annual operating load or capacity factor, and have boiler temperature profiles and other factors that affect pollution control devices. A few commenters supplied data or indicated the cost of control for certain units. One commenter stated that reasonably available control technology (RACT) analysis for an unidentified, 350 million British thermal units (mmBtus)/hr coal-fired stoker boiler indicated that the only technically feasible NO_X control identified by boiler and NO_X control experts was conversion to fluidized bed combustion at a cost of over $11,000/ton based on year-round operation and over $26,000/ton considering only the ozone season. Another commenter cited EPA's "Alternative Control Techniques Document: NO_X Emissions from Industrial/Commercial/Institutional Boilers' (March 1994) (1994 ACT), indicating cost effectiveness of SCR for a 400 mmBtu/hr pulverized coal boiler of $3,400–$4,200/ton and cost effectiveness of SNCR for a 470 mmBtu pulverized coal boiler (with low NO_X burners and a 50 percent load factor) of more than $1,800/ton. An additional commenter indicated costs in excess of $2,500 per seasonal ton at the Tobaccoville facility (in 1990 dollars).

In light of the limited control cost data provided by commenters, we conclude that at this time we lack sufficient cost data to show whether there is a significant difference in the average cost of controlling NO_X emissions from cogeneration units, as compared to non-cogeneration units. The 1994 ACT costs cited by one commenter are not relevant because the boilers involved were not cogeneration units. In addition, the cited costs were early estimates by the Agency on the cost of SCR and SNCR and have been superceded by later data and documents. Further, the commenters' indicated that costs at the coal-fired stoker and at the Tobaccoville facility do not necessarily support the claim that average costs of controlling NO_X at cogeneration units are higher than such costs at non-cogeneration units. Due to economies of scale, smaller units, like some industrial cogeneration units and smaller utility units, may have costs that are higher than the average costs. We acknowledge that the actual cost impacts will vary from unit to unit, with the costs being lower for some and higher for others. In our analysis, we presented average costs of control and understood that some units may have higher costs than the average. We note that units may participate in a trading program that allows for the buying of allowances for units that have more difficulty controlling NO_X emissions.

Furthermore, we note that we have cost information on one other cogeneration unit. In our cost analysis of EGUs, we used an average capital cost of $69.70 to $71.80 per kilowatt for SCR on a 200 MWe coal-fired EGU. *See* "Analyzing Electric Power Generation Under the CAAA,'' U.S. EPA, March 1998, Docket No. OAR–2001–0008, Item No. V–C–03 at A5–7 (Table A5–5). The record shows a capital cost of $58 per kilowatt for SCR on a new coal-fired cogeneration unit. *See* "Status Report on NO_X Control Technologies and Cost Effectiveness for Utility Boilers,'' Northeast States for Coordinated Air Use Management and Mid-Atlantic Regional Air Management Association, June 1998, Docket No. OAR–2001–0008, Item No. VI–B–05 at 151–53. We maintain that this cost is reasonably consistent with the average cost that we determined for all EGUs.[17] However, as commenters noted, industrial cogeneration units cover a wide range of firing types and fire a wide range of fuels. Since the cogeneration unit used as part of the basis for the control costs for EGUs was a medium-size, pulverized coal plant very similar to many coal-fired utility boilers, it is not necessarily representative of other types of boilers used for industrial cogeneration units such as stoker boilers firing a combination of fuels. Since we have limited control cost data for such other types of industrial cogeneration units, we believe that we do not have a sufficient record at this time to show whether there is a significant difference in the average cost of controlling NO_X emissions from these units.

4. What Revisions Are Being Made to the Definition of EGU in the NO_X SIP Call and the Section 126 Rule?

In today's final rule, we are addressing three aspects of the EGU definition. First, for purposes of the NO_X SIP Call and the Section 126 Rule and in a change from the February 22, 2002 proposed rule (*see* 67 FR 8401–8410), we are finalizing an EGU definition that applies to cogeneration units the "one-third potential electrical output/25 MWe sales'' criteria in classifying the units as EGUs or non-EGUs. For all other units, we are continuing to apply the basic approach used in the NO_X SIP Call Rule, described in the December 24, 1998 supplemental action (63 FR 71233), and the approach in the Section 126 Rule for such classification. Second, we are finalizing some minor changes to the categorization (based on dates of commencement of operation) of units under the NO_X SIP Call definition of EGU (set forth in section II.A.2 above) for purposes of applying the firm-contract criterion used to classify units as EGUs. While the NO_X SIP Call categorizes units as those commencing operation before January 1, 1996 and those commencing operation on or after January 1, 1996, today's final rule categorizes units as those commencing operation before January 1, 1997, those commencing operation in 1997 or 1998, and those commencing operation on or after January 1, 1999. These new categories based on commencement of unit operation are the same as the categories adopted in the January 18, 2000 Section 126 final rule, under which units commencing operation before 1999 and generating electricity for sale, but not for sale under a firm contract to the grid (*i.e.,* not under a guaranteed commitment to provide the electricity), were classified as non-EGUs and units commencing operation in 1999 or thereafter and generating any electricity for sale were generally classified as EGUs. Today's final rule uses this same approach to classify units as EGUs or non-EGUs, except for the application to cogeneration units of the "one-third potential electrical output/25 MWe sales'' criteria. Third, we are also finalizing some minor changes to the terminology, and minor corrections of awkward or inconsistent wording and grammatical errors in the applicability provisions. For example, we are adopting the term "potential electrical output capacity'' and the definitions of the terms "electricity for sale under firm contract to the electric grid,'' "potential

[17] We also note that the dollar per ton cost for this installation is $2,800 to $3,000 per ton of NO_X removed. This is higher than the average cost for EGUs because the unit started at a low NO_X rate (0.16 lb/mmBtu) and controls down to 0.07–0.08 lb/mmBtu, not because the unit is a cogenerator. If the unit only generated electricity and had the same starting NO_X rate, the cost would be the same.

electrical output capacity,'' "nameplate capacity,'' and "maximum design heat input'' used in the January 18, 2000 Section 126 Rule.

a. *Application of the "one-third potential electrical output/25 MWe sales'' criteria, in lieu of the firm-contract criterion, to cogeneration units.* As explained in the NO_X SIP Call Rule, described in the December 24, 1998 supplemental action (63 FR 71233), and the Section 126 Rule, we adopted the approach of using the firm-contract criterion for units (non-cogeneration and cogeneration units) that commenced operation before 1999. We stated that the criterion provides a reasonable transitional means of making the EGU/non-EGU classification since, for units commencing operation in 1999 or thereafter, a unit that generates any electricity for sale is classified as an EGU. We explained that the firm-contract criterion provides a reasonable way of identifying which cogeneration units have been significantly enough involved in the business of generating electricity for sale that their owners have provided guaranteed commitments to provide electricity from the units to one or more customers. We also stated that the historical information necessary to apply the firm-contract criterion to cogeneration units (and other units) is already available to us. Capacity involved in sales of electricity "under firm contract to the electricity grid'' has been generally included on EIA form 860A (called EIA form 860 before 1998) or reported to EIA as capacity projected for summer or winter peak periods on EIA form 411 (Item 2.1 or 2.2, line 10). The historical information from these forms is publicly available.

Nevertheless, in today's final rule, we are adopting the "one-third potential electrical output/25MWe sales'' criteria for classifying cogeneration units as EGUs or non-EGUs. The reasons for this approach are discussed below in II.A.4. Regardless of when a cogeneration unit commenced or commences operation, a cogeneration unit supplying more than one-third of its potential electrical output and more than 25 MWe to a utility power distribution system for sale during any year in the relevant period is classified as an EGU, and a cogeneration unit that does not meet these criteria is classified as a non-EGU. As stated above, criteria are used in order to determine whether a cogeneration unit is exempt from the Acid Rain Program under section 402(17)(C) of the CAA, as implemented under § 72.4(b)(4) of the Acid Rain regulations. *See* 40 CFR 72.4(b)(4); and 58 FR 15634, 15636–38 (1993). Consequently, in implementing the use of the "one-third'' potential electrical output/25 MWe sales'' criteria for classifying cogeneration units in the NO_X SIP Call and in the Section 126 Rule, today's final rule references § 72.4(b)(4). Thus, in general, a cogeneration unit that meets the criteria for an unaffected unit in the Acid Rain Program under § 72.4(b)(4) for the relevant time period is defined as a non-EGU, while a cogeneration unit that fails to meet the criteria for such exemption for the relevant time period is defined as an EGU. Moreover, for cogeneration units commencing operation before January 1, 1997, the relevant period is 1995–1996; for cogeneration units commencing operation during 1997–1998 the relevant period is 1997–1998; and for units commencing operation on or after January 1, 1999, the relevant period is 1999 and thereafter. These same periods or categories are used in classifying non-cogeneration units as EGUs or non EGUs. We are adopting the categories so that a consistent set of categories applies to all units (either cogeneration or non-cogeneration units), which will simplify and facilitate the categorization of units by EPA, States, and others.[18] As discussed below, we are continuing to apply the firm-contract criterion (for units commencing operation before 1999) or the electricity sales criterion (for units commencing operation in or after 1999) for classifying non-cogeneration units as EGUs or non-EGUs.

b. *Application of the firm-contract criterion to non-cogeneration units.* As noted above, in the NO_X SIP Call Rule [as described in the December 24, 1998 supplemental action (63 FR 71233)] and the Section 126 Rule, we adopted the approach of using the firm-contract criterion for non-cogeneration units (as well as for cogeneration units) that commenced operation before 1999. In the February 22, 2002 proposed rule, we did not reconsider that general approach for non-cogeneration units, but only for cogeneration units. However, we did propose minor changes in the categorization of non-cogeneration units based on their date of commencement of operation. We proposed to adopt commencement of operation before 1999 or on or after January 1, 1999 as the dividing line between units to which the firm-contract criterion are applied and those to which the electricity sales criterion are applied. Further, for application of the firm-contract criterion, we proposed to distinguish between units commencing operation before 1997 and those commencing operation in 1997 or 1998. Some commenters on the proposed rule argued for the keeping of the "firm contract'' language for units commencing operation in 1999 or later, especially if we would continue with our proposed definition of EGUs with regard to cogeneration units.

In today's final rule, we are finalizing, for non-cogeneration units, the categorization of units under the NO_X SIP Call as those units commencing operation before January 1, 1997, those commencing operation in 1997 or 1998, and those commencing operation on or after January 1, 1999.

The firm-contract criterion is not applied to non-cogeneration units commencing operation on or after January 1, 1999. The classification of units commencing operation on or after January 1, 1999 will be based on whether the unit produces any electricity for sale. In general, any non-cogeneration unit that produces electricity for sale will be an EGU, except that the non-EGU classification will apply to a unit serving a generator that has a nameplate capacity equal to or less than 25 MWe, from which any electricity is sold, and that has the potential (determined based on nameplate capacity) to use 50 percent or less of the potential electrical output capacity of the unit.

As discussed in the February 22, 2002 proposed rule, for several reasons, we are establishing January 1, 1999 as the cutoff date for applying EGU and non-EGU definitions based on electricity sales under firm contract to the grid and the start date for applying EGU and non-EGU definitions based on electricity sales. First, information is available to us on electricity sales on a calendar year basis only. Consequently, the classification of units based on whether the generators that they serve are involved in firm-contract electricity sales must be made on a calendar year basis, and any cutoff must start on January 1. Second, use of the January 1,

[18] While we wish to be as consistent as possible in the definitions used in the NO_X SIP Call and the definitions used in the Section 126 Rule, there is an important difference in the reason for categorizing units in the two rulemakings. In the NO_X SIP Call, the definitions are used to set the State budgets and therefore need to focus on 1995 and 1996, the base years used for developing budgets. State-specific growth rates were used to take into account units commencing operation after the base years. The NO_X SIP Call model rule (in part 96) did not use these definitions in the applicability and allowance allocation provisions, and States adopted their own applicability and allowance allocation provisions in their SIPs. Thus, the portion of the definitions that affects the NO_X SIP Call is the portion pertaining to units in operation before January 1, 1997. In the Section 126 Rule, the definitions are used for purposes of determining applicability and allocating allowances. Thus, in the Section 126 Rule, the definitions must address units commencing operation after 1996, as well as those operating in 1995 and 1996.

1999 cutoff date for the NO_X SIP Call is consistent with the use of that same cutoff date in the Section 126 Rule. Third, the January 1, 1999 cutoff date will limit the ability of owners or operators of new units that might otherwise qualify as large non-EGUs from obtaining small EGU classification for the units and thereby avoiding all emission reduction requirements. For example, since the cutoff date and the relevant period for determining electricity sales are past, the owner of a large new unit that would otherwise not serve a generator will not be able to obtain small EGU classification simply by adding a very small generator (*e.g.*, 1 MWe) to the unit and selling a small amount of electricity under firm contract to the grid.

c. *Application of Section 126 terms and definitions and correction of awkward or inconsistent wording and grammatical errors.* We also are finalizing for use in the NO_X SIP Call the same term "potential electrical output capacity,'' and the same definitions of the terms "electricity for sale under firm contract to the electric grid,'' "potential electrical output capacity,'' "nameplate capacity,'' and "maximum design heat input,'' adopted in the January 18, 2000 Section 126 final rule and used in the EGU definition in the regulations (*i.e.*, part 97) implementing the Section 126 program. The basis for these terms and definitions is set forth above.

In addition, we are correcting some awkward or inconsistent wording and grammatical errors without making any substantive change in the EGU and non-EGU definitions. For example, instead of referring to units commencing operation "on or after January 1, 1997 and before January 1, 1999'' as in the February 22, 2002 proposed rule, the final regulations refer to units commencing operation "in 1997 or 1998.''

By further example, with regard to units classified as EGUs, the proposed rule refers to a unit commencing operation before January 1, 1997 or in 1997 or 1998 that "had'' a nameplate capacity greater than 25 MWe and refers to a unit commencing operation on or after January 1, 1999 "with'' the requisite nameplate capacity. With regard to units classified as non-EGUs, the proposed rule refers to a unit commencing operation before January 1, 1997 or in 1997 or 1998 that "has'' a maximum design heat input greater than 250 mmBtu/hr and refers to a unit commencing operation on or after January 1, 1999 "with'' the requisite maximum design heat input. This inconsistent wording concerning nameplate capacity and maximum design heat input, where sometimes the past tense, sometimes the present tense, and sometimes no tense are used for units that had already commenced commercial operation in the past, is confusing. The final regulations consistently reference nameplate capacity and maximum design heat without using past or present tense. The regulations refer to generators "with'' the requisite nameplate capacity and units "with'' the requisite maximum design heat input.

By further example, the proposed rule refers to EGUs that "commenced operation'' before January 1, 1997 or in 1997 or 1998 serving a generator that "produced electricity for sale'' and to EGUs that "commence operation'' on or after January 1, 1999 that serve a generator that "produces electricity for sale.'' The proposed rule also refers to non-EGUs that "commenced operation'' before January 1, 1997 or in 1997 or 1998 that "did not serve'' a generator "producing electricity for sale'' and to non-EGUs that "commence operation'' on or after January 1, 1999 that "at no time serves'' or "at any time serves'' a generator "producing electricity for sale.'' This inconsistent wording and use of past and present tenses is also confusing. For example, some units in the category of 1999 or later commencement of operation have already commenced operation while others will commence operation in the future. Yet, the present tense is used in reference to all such units. The final regulations consistently reference commencement of operation and production of electricity without using past or present tense.

d. *Final EGU and non-EGU definitions.* For the reasons discussed above, we are adopting the following definitions of EGU and non-EGU for the NO_X SIP Call and the proposed definitions discussed above (in footnotes 9, 10, 11, and 12) for the terms "electricity for sale under firm contract to the electric grid,'' "potential electrical output capacity,'' "nameplate capacity,'' and "maximum design heat input'' used in the EGU and non-EGU definitions. (The EGU and non-EGU definitions, and definitions for related terms, adopted today for the Section 126 Rule are set forth below in the revised rule language accompanying this preamble.)

(a) The following units are classified as EGUs:

(1) For non-cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit serving during 1995 or 1966 a generator producing electricity for sale under a firm contract to the electric grid.

(B) For units commencing operation in 1997 or 1998, a unit, serving during 1997 or 1998 a generator producing electricity for sale under a firm contract to the electric grid.

(C) For units commencing operation on or after January 1, 1999, a unit serving at any time a generator producing electricity for sale.

(2) For cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit that fails to qualify as an unaffected unit under 40 CFR 72.6(b)(4) for 1995 or 1996 under the Acid Rain Program.

(B) For units commencing operation in 1997 or 1998, a unit that fails to qualify as an unaffected unit under 40 CFR 72.6(b)(4) for 1997 or 1998 under the Acid Rain Program.

(C) For units commencing operation on or after January 1, 1999, a unit that fails to qualify as an unaffected unit under 40 CFR 72.6(b)(4) for any year under the Acid Rain Program.

(b) The following units are classified as non-EGUs:

(1) For non-cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit not serving during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid.

(B) For units commencing operation in 1997 or 1998, a unit not serving during 1997 or 1998 a generator producing electricity for sale under a firm contract to the electric grid.

(C) For units commencing operation on or after January 1, 1999, a unit:

(i) At no time serving a generator producing electricity for sale; or

(ii) At any time serving a generator with a nameplate capacity of 25 MWe or less producing electricity for sale, and with the potential to use no more than 50 percent of the potential electrical output capacity of the unit.

(2) For cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit that qualifies as an unaffected unit under 40 CFR 72.6(b)(4) for 1995 and 1996 under the Acid Rain Program.

(B) For units commencing operation in 1997 or 1998, a unit that qualifies as an unaffected unit under 40 CFR 72.6(b)(4) for 1997 and 1998 under the Acid Rain Program.

(C) For units commencing on or after January 1, 1999, a unit that qualifies as an unaffected unit under 40 CFR 72.6(b)(4) for each year under the Acid Rain Program.

(c) Units classified as EGUs or non-EGUs under paragraphs (a) and (b) are classified as large or small as follows:

(1) A unit under paragraph (a) serving a generator with a nameplate capacity greater than 25 MWe is a large EGU.

(2) A unit under paragraph (a) serving a generator with a nameplate capacity equal to or less than 25 MWe is a small EGU.

(3) A unit under paragraph (b) with a maximum design heat input greater than 250 mmBtu/hour is a large non-EGU.

(4) A unit under paragraph (b) with a maximum design heat input equal to or less than 250 mmBtu/hour is a small non-EGU.

5. What Is the Effect on Cogeneration Unit Classification of Applying "One-Third Potential Electrical Output Capacity/25 MWe Sales'' Criteria, Rather Than the Same Methodology as Used for Other Units?

The petitioner in *Michigan* who successfully challenged the lack of application of the "one-third potential electrical output capacity/25 MWe sales'' criteria to cogeneration units claimed that the failure to apply such criteria would result in "sweeping previously unaffected non-EGUs into the EGU category.'' Brief of Petitioner CIBO at 4 (submitted in *Michigan*). The petitioner further suggested that, without the application of these criteria, "any sale of electricity will make a non-EGU a more stringently regulated EGU.'' Reply Brief of Petitioner CIBO at 1 (submitted in *Michigan*).

As discussed above, large EGUs and large non-EGUs are included in the determination of the amount of a State's significant contribution to nonattainment in another State. No reductions by small EGUs or small non-EGUs are included in that determination.

Neither the petitioner nor any party that commented in the NO_X SIP Call or the Section 126 rulemakings identified any specific, existing cogeneration units that, without the application of the "one-third potential electrical output capacity/25 MWe sales'' criteria, would be classified as large EGUs but that, with the application of such criteria, would be classified as either large or small non-EGUs. In fact, one commenter supporting the "one-third potential electrical output capacity/25 MWe'' sales criteria stated that applying the criteria to the NO_X SIP Call "would not alter the Agency's baseline emissions inventory, since cogeneration units were, for the most part, classified correctly as non-EGUs in EPA's current data base.'' *See* Responses to the 2007 Baseline Sub-Inventory Information and Significant Comments for the Final NO_X SIP Call (63 FR 57356, October 27, 1998), May 1999 at 9. In our proposed rule in response to the Court's decision, we again asked commenters to identify any specific, existing cogeneration units that, without the application of the "one-third potential electrical output capacity/25 MWe sales'' criteria, would be classified as large EGUs but that, with the application of such criteria, would be classified as either large or small non-EGUs. One commenter stated that up to 16 cogeneration units in the paper and pulp industry units would be affected by the change in EGU definition. However, the commenter not only failed to provide the names of any specific units but also stated that it lacked sufficient information to determine whether any of the units were selling electricity under firm contract to the grid. In short, the commenter did not really know whether the 16 units would actually be treated as EGUs if the "one-third potential electrical output capacity/25 MWe sales'' criteria were not applied.

For today's final rule, in light of the lack of such specific information in the comments, we were unable to identify any small cogeneration units whose classification as EGUs or non-EGUs will change in light of the changes in the EGU and non-EGU definitions adopted in the final rule. The only exception may be for units at the Tobaccoville facility, which are addressed above. However, for the reasons discussed above, we will consider reclassification of these units during the SIP revision approval process. Further, it is conceivable that there are other small cogeneration units that need to be reclassified from EGUs to non-EGUs and that, therefore, further adjustments to the budgets of particular States may be necessary. We will also make such further adjustments during the SIP approval process when we receive the information necessary to support such reclassifications of small cogeneration units. Because we anticipate that few, if any, units currently treated in the budgets as EGUs qualify as small cogeneration units, we expect few, if any, revisions to the budgets resulting from today's final rule, and if any revisions do result, we anticipate that they will be very small and will not affect most States.

In order to facilitate the SIP approval process, we request participants in the process of developing SIP revisions in response to today's final rule to identify by name, location, and plant and point identification any cogeneration unit that they believe should be classified as a large or small non-EGU under the methodology in today's final rule and that would have been classified differently as a large or small EGU under the methodology in the proposed rule. We also request identification by name, location, and plant and point identification of any cogeneration unit that should be classified as a large or small EGU under today's final rule methodology and that would have been classified as a large or small non-EGU under the proposed methodology. In addition, we request information supporting any claimed EGU, non-EGU, large, or small classification of each identified unit.

Persons that identify units as cogeneration units or small cogeneration units (under the "one-third potential electrical output capacity/25 MWe sales'' criteria) should submit the following information to confirm their identification:

(1) A description of the facility to demonstrate that the facility meets the definition of a "cogeneration unit'' under 40 CFR 72.2.

(2) Data describing the annual electricity sales from the unit for every year from the unit's commencement of operation through the present. To provide this information, persons should submit the same form as they used to report the information to the EIA, or if they have not reported the information to EIA, provide the same information on annual electricity sales as was or would have been required to be reported to EIA.

(3) Information stating and supporting the value of the unit's maximum design heat input.

B. What Are the Control Levels and Budget Calculations for Stationary Reciprocating Internal Combustion Engines (IC Engines)?

In the February 22, 2002 action, we proposed that highly cost-effective controls are available for stationary IC engines. We proposed to assign a 90 percent emissions decrease on average for large natural gas-fired rich-burn, diesel, and dual fuel IC engines. For large natural gas-fired lean-burn IC engines, we proposed to assign a percent reduction from within the range of 82 to 91 percent. Based on available data regarding demonstrated costs, effectiveness, availability, and feasibility of low emission combustion (LEC) technology, and consideration of comments received in response to the proposal, we stated that we would determine a percent reduction number to use in calculating this portion of the NO_X SIP Call budget decrease.

Today, we are recalculating the budgets to reflect a control level of 82 percent for the natural gas-fired lean-burn IC engines. Because the vast majority of large natural gas-fired IC engines are lean burn, we are applying the 82 percent reduction to all large natural gas-fired IC engines for the purpose of setting this portion of the budget. For the other IC engine subcategories (diesel and dual fuel) we are using 90 percent control, as proposed.

1. Determination of Highly Cost-Effective Reductions and Budgets

As described in the NO_X SIP Call final rule, after determining the degree to which NO_X emissions, as a whole from the particular upwind States, contribute to downwind nonattainment or maintenance problems, we determined whether any amounts of the NO_X emissions may be eliminated through controls that, on a cost-per-ton basis, may be considered to be highly cost effective. By examining the cost effectiveness of NO_X controls, we determined that an average of approximately $2,000 per ton removed is highly cost effective. We first projected the total amount of NO_X emissions that sources in each covered State would emit, accounting for their projected growth and measures required under the CAA, in 2007. We then projected the total amount of NO_X emissions that each of those States would emit in 2007 if each State applied the highly-cost effective measures (the State's budget). The difference between the 2007 base inventory and the budget for each State is that State's "significant contribution'' to downwind nonattainment. For a more detailed discussion of the determination of cost-effective reductions and budgets, see the October 27, 1998 NO_X SIP Call (63 FR 57399–57403 and 57405, respectively).

2. What Are the Key Comments We Received Regarding IC Engines?

The following describes key comments regarding IC engines and provides our responses. Additional comments and responses are contained in the Response to Comments (RTC) document associated with this rulemaking. Related information is also contained in the Technical Support Document (TSD) (revised version) associated with this rulemaking.

a. Level of NO_X Control

(1) NO_X uncontrolled emission rate.

Comment: Several commenters suggested that we should rely on the July 2000 AP–42 emission factor documents (Docket No. OAR–2001–0008, Item Nos. XII–D–09 and XII–D–10) for the average uncontrolled emission rates [11.7 g/bhp-hr (grams per brake horsepower-hour) for 2-stroke engines and 15.1 g/bhp-hr for 4-stroke engines]. The commenters object to our use of a higher value (16.8 g/bhp-hr) as the uncontrolled level.[19] The commenters state that the July 2000 AP–42 factors are best because:

- They are based on actual engine emission tests;
- The engines tested are similar to "large'' NO_X SIP call engines;
- They are not based on horsepower categories;
- They tested both 2- and 4-stroke engines; and
- They have documented quality control.

Response: We reviewed the data used to update AP–42. In order to focus on the large engines addressed in the NO_X SIP Call, as suggested by commenters, we examined test data from those engines greater than 2,000 horsepower (hp) operating at greater than 90 percent load. The large engines in this data base cover only 2 engine models and 8 tests; both models are 4-stroke engines. According to comments from the Interstate Natural Gas Association of America (INGAA), about 85 percent of the large engines in the NO_X SIP Call area are 2-stroke. Furthermore, as described in the July 2000 AP–42 document, the data presented do not differentiate between uncontrolled lean-burn engines and engines that may be turbocharged.[20] Thus, the average "uncontrolled'' emissions reported may include some engines with lower NO_X emissions due to the turbocharging. We conclude that this data base is helpful but too limited to stand by itself considering the large amount of data available from other sources. Instead, the AP–42 data must be reviewed along with other data as described below.

Comment: Commenters state that our 16.8 g/bhp-hr average is derived from "mostly'' new engine models in 1991, not the entire, current population of existing engines. According to commenters, the 1994 ACT document numbers are not representative of older NO_X SIP Call type engines, the details of the data are unavailable, and the 16.8 value cannot be replicated. The commenters indicate that our weighted average approach does not correspond to engine models in the NO_X SIP Call population, that the NO_X 1994 ACT reflects 1991 manufacturer's letters for new, 4-stroke engines, and that we need to make these letters available.

Response: We have examined data from the pipeline industry, data recently collected by the Agency, and data from the 1994 ACT document (see RTC or TSD for details). These include data from large engines covered by the NO_X SIP Call as suggested by some commenters. We believe the data support the 16.8 value proposed, as described below.

Emissions data compiled by three pipeline industry companies provide support to the 16.8 g/bhp-hr value proposed by us or a slightly higher value. Test data are contained in two letters to the Ozone Transport Commission (OTC) in November 2000. Based on a survey of LEC retrofit installation in NO_X SIP Call States, two pipeline companies in a November 20, 2000 letter to the OTC,[21] presented data on pre-LEC and post-LEC emissions for 86 engines in NO_X SIP Call States. Most of the engines are relatively large, at 2000 hp or greater. Table 1 of the letter summarizes the data and states that the average uncontrolled NO_X emissions level for these 86 engines is 16.8 g/bhp-hr, identical to the level we proposed. Considering only those engines greater than or equal to 2,000 hp, there are 66 engines with an average uncontrolled emissions rate of 18.2 g/hp-hr (see RTC or TSD for details). Additional data in the same letter provide pre-LEC and post-LEC data for 20 engines. The letter states that the average uncontrolled NO_X emissions for the 20 engines is 14.1 g/bhp-hr. Another major pipeline company also sent a letter (November 22, 2000) to the OTC presenting uncontrolled and RACT emission rates for 62 engines retrofit with LEC (see RTC or TSD for details). The average uncontrolled emission rate, considering all 62 engines from this data set, is 17.6 g/bhp-hr. The weighted average of these three data sets is 17.5 g/bhp-hr.[22]

In response to comments, we collected additional test data to better determine controlled and uncontrolled emission levels from the current population of large engines in the NO_X SIP Call area. Forty-two data points were collected (see RTC or TSD for details). The average uncontrolled NO_X level from this data is 16.7 g/bhp-hr, nearly identical to the proposed level of 16.8 g/bhp-hr.

As suggested by commenters, we also examined the available data separately for 2- and 4-stroke engines. The test data for the large IC engines in the NO_X SIP Call area indicate uncontrolled levels of 16.4 and 18.9, respectively, for the 2-

[19] **Note:** Use of a higher uncontrolled value would result in a higher overall percentage control value. For example, assuming a control level of 3.0 g/bhp-hr the percentage control value would be 82 percent using 16.8 g/bhp-hr as the uncontrolled level and 75 percent using 12.0 as the uncontrolled level.

[20] See footnotes "(a)'' to Tables 3.2–1 and 3.2–2 in the July 2000 AP–42 document.

[21] The letter addressed concerns regarding the OTC's development of a set of model NO_X rules, including rules for stationary IC engines.

[22] The weighted average was calculated as follows: $(66 \times 18.2 + 14 \times 14.1 + 62 \times 17.6)$ divide sum by 142 = 17.5.

and 4-stroke engines. Using information from the pipeline industry that about 85 percent of the engines in the NO_X SIP Call area are 2-stroke, the weighted average of the 16.4 and 18.9 values is 16.8, identical to our proposed value.[23]

As described in the 1994 ACT document for stationary IC engines, uncontrolled emission levels were provided to us by several engine manufacturers. Most manufacturers provided emission data only for current production engines, but some included older engine lines as well. The manufacturers' letters were placed in the docket. These emission levels were tabulated and averaged for engines with similar power ratings. For engines greater than 2000 hp, the average uncontrolled emission rate from 55 engines is approximately 16.8 g/bhp-hr. As noted in the TSD, there are several reasons to use the 1994 ACT document data. Using the applicable 1994 ACT document is consistent with how we treated other non-EGU source categories in the NO_X SIP Call rulemaking. The 1994 ACT document provides a comprehensive look at the IC engine class and has the advantage of using a consistent data set for uncontrolled emissions, costs, and controls. The 1994 ACT document uses a large data set from which to draw conclusions. The 1994 ACT document test data are available in several horsepower size categories which is important since we chose not to calculate emissions reductions from the smaller IC engines.

In summary, based on the 1994 ACT document data, the data contained in the industry letters to OTC and data we recently collected, there is considerable agreement with the 16.8 g/bhp-hr uncontrolled emission rate value that we proposed. The data do not support commenters suggestion for a lower value, namely 11.7 g/bhp-hr for 2-stroke engines and 15.1 g/bhp-hr for 4-stroke engines. Therefore, we conclude that use of the 16.8 g/bhp-hr level is appropriate to represent average, uncontrolled emissions.

(2) NO_X controlled emission rate with LEC technology.

Comment: Appendix B to INGAA's April 22, 2002 comment letter lists 226 lean-burn large and small IC engines in the NO_X SIP Call States that are retrofit with LEC technology and for which they could obtain State NO_X permit limits. The average post-control NO_X permit levels for 2-stroke and 4-stroke engines are reported to be 5.0 and 3.7, respectively. The INGAA states that NO_X permit limits are appropriate for use in calculating the average post-control emission rate for lean-burn engines in the NO_X SIP Call area for the following reasons:

- These engines are located in the NO_X SIP Call States, and represent the same makes and models as the large NO_X SIP Call engines,
- These engines operate under State permit limits that reflect the emission control achieved by LEC on actual and identified individual engines,
- The emission control limits were established as the result of a formal regulatory process conducted by the State permitting agencies, and
- The LEC retrofits are consistent with the technology and costs identified by our NO_X SIP Call TSDs.

Response: We disagree that permit limits are appropriate for determining the post-control emission rate. Permit limits generally do not reflect the actual emission rate and, thus, are not appropriate to determine the emission rates to be expected from installation of LEC technology. For example, State records indicate permit limits of 18 and 8 even though LEC technology is in place and the target emission rate in the State RACT plan is 3 for both engines.[24] In another case, the permit level is 3.0, but the actual rate is reported as 1.7.[25] The permit limits for six engines at a station in one State are 3.0 g/bhp-hr while the test data show emissions at less than 1.1 g/bhp-hr for each engine.[26] We agree with the comment that LEC retrofits are consistent with the costs identified by our NO_X SIP Call TSDs.

Further, if we were to use permit rates, it makes no sense to ignore permit limits set in areas outside the NO_X SIP Call region. California and Texas permits, for example, have very low emission rates for IC engines.[27] The permit levels suggested by commenters are limited because the permits generally reflect RACT requirements. However, highly cost-effective controls under the NO_X SIP Call are not limited to RACT-level stringency and should take into account improvements in control efficiency and cost effectiveness that have occurred over the last several years since the RACT generation of controls.

Comment: Commenters state that data we used to support the proposed controlled levels[28] are for new or rebuilt engines—not retrofits—and therefore, cannot be relied upon. They suggest we should use NO_X limits for engines retrofit with LEC in State permits and that the permits suggest no more than a 70 percent reduction.[29] Several commenters indicate it is important to examine the specific engines in the NO_X SIP Call States to determine whether the reductions we assumed are achievable. Comments suggest that industry experience through RACT retrofits, has demonstrated that the stringent emission rates of 1.5 to 3.0 g/bhp-hr are not achievable on many engines and the average emission reduction to be expected for LEC retrofits is 70 percent. Comments from the New Hampshire Department of Environmental Services expressed support for a 90 percent control level.

Response: The commenters and EPA agree that LEC technology is a proven technology for natural gas-fired lean-burn engines.[30] There is not agreement, however, on the appropriate level of control to assume from installation of the LEC technology. In response to comments, we collected additional test data, including data representative of emissions from large engines in the NO_X SIP Call area. To determine the appropriate level of control, we examined all available data, including data from State permits and test data on new, rebuilt, and retrofit engines with LEC technology. These data were placed in the docket. A summary of the data is provided below. As suggested by commenters, the data have been organized to show LEC retrofit test data

[23] For large lean-burn IC engines in the NO_X SIP Call States, 2-stroke engines represent 83 percent of the total large engines and 85 percent of the total large engine horsepower. (From INGAA's April 22, 2002 comments, pages 2 and 10.) (Docket No. OAR–2001–0008, Item No. XII–D–09).

[24] See docket for e-mail from John Patton dated May 30, 2002 and attachments. (Docket No. OAR–2001–0008, Item No. 0917).

[25] See Docket No. OAR–2001–0008, Item No. XII–M–01 for November 20, 2000 letter, appendices A & B.

[26] See Docket No. OAR–2001–0008, Item No. 0921 for June 5, 2002 fax from Randy Hamilton.

[27] Ventura County Rule 74.9 (in effect September 1989 to December 1993) applied to engines greater than or equal to 100 hp and required 125 ppm (1.7 g/bhp-hr) or 80 percent control. Current Ventura County Rule 74.9 requires 45 ppmv (0.6 g/bhp-hr) or 94 percent control. For best available retrofit control technology, California Air Resources Board selected for engines greater than or equal to 100 hp 65 ppm (0.9 g/bhp-hr) or 90 percent control, based on Sacramento Air Quality Management Division Rule 412. In Texas, requirements applicable in Houston are 0.5–0.6 g/bhp-hr for lean-burn engines.

[28] We proposed to select a value within the range of 82 to 91 percent control (1.5-3.0 g/bhp-hr controlled level assuming 16.8 uncontrolled level) based primarily on information in the 1994 ACT document.

[29] This equates to a 5.0 g/bhp-hr limit, assuming an uncontrolled level of 16.8 g/bhp-hr.

[30] For example, November 30, 1998 letter from INGAA to EPA (Docket No. OAR–2001–0008, Item No. 0919), February 16, 1999 memo from INGAA to Tom Helms, EPA (Docket No. OAR–2001–0008, Item No. XII–K–38), and April 26, 2002 comment letter from Kinder Morgan (Natural Gas Pipeline Company of America) (Docket No. OAR–2001–0008, Item No. XII–D–24).

for large engine models found in the NO_X SIP Call area.

The INGAA in their April 22, 2002 comments, identified the most common models of large natural gas transmission engines in the NO_X SIP Call area. In addition, INGAA identified engines that had been retrofit with LEC in the NO_X SIP Call area. In response to these comments, we contacted the various EPA Regional Offices to obtain information on specific large lean-burn engines used by the gas pipeline industry that have been retrofit with LEC in the NO_X SIP Call area. Data from the EPA Regional Offices and other emission test results were obtained. The results for large engines in the NO_X SIP Call area show that 43 of the 58 tests have NO_X emission levels at or below 3.0 g/bhp-hr (see RTC or TSD for details). The LEC technology retrofit on these large engines achieved, on average, an emission rate of 2.3 g/bhp-hr.

As suggested by commenters, we also examined the available data separately for 2- and 4-stroke engines (see TSD for details). Test data for the large IC engines in the NO_X SIP Call area indicate controlled levels of 2.3 and 2.5, respectively, for the 2- and 4-stroke engines. Assuming 85 percent of the engines in the NO_X SIP Call area are 2-stroke, the weighted average of the 2.3 and 2.5 values is 2.3.

As described in the TSD, looking at a broader set of data yields similar results. That is, considering data from large engines both inside and outside the NO_X SIP Call area shows that 60 of the 79 tests have NO_X emission levels at or below 3.0 g/bhp-hr (see TSD for details). The LEC technology retrofit on these large engines achieved, on average, an emission rate of 2.2 g/bhp-hr. Considering the similarity of the resulting average controlled emission rates and the ample set of data for large engines in the NO_X SIP Call area, we agree with commenters that it is reasonable to focus on the set of data for large engines in the NO_X SIP Call area.

The set of data for large engines in the NO_X SIP Call area cover 80 percent of the engine models in the NO_X SIP Call area. However, emission rates for some of the engine models for which test data are not available are likely to be higher than the 2.3 average value. For example, Worthington and Nordberg engines are known to be difficult to retrofit. One vendor reported achieving a level of 6 g/bhp-hr for certain Worthington engines.[31] As noted in the TSD, a Worthington UTC 165 in New York reduced NO_X emissions to 4.4 g/hp-hr. A pipeline company commented that they operate six Worthington engines and that 4.0 g/bhp-hr is their targeted emission reduction level, based on vendor projections.[32] Thus, it appears that a 4.0 to 6.0 g/bhp-hr level is achievable on these difficult to retrofit Worthington engines. At this time, we believe that 5.0 g/bhp-hr is a reasonable emission rate, on average, for engines known to be difficult to retrofit. Although not all of the 20 percent of engine models for which test data are not available are likely to be difficult to retrofit, we believe it is reasonable to treat these engines as one group and to conservatively assume that this group of engines would achieve a 5.0 level, on average.

In summary, based on the available test data, we believe it is reasonable to assume about 80 percent of the large engines in the NO_X SIP Call area are able to meet a 2.3 level, on average, and that 20 percent are able to meet a 5.0 level, on average with LEC technology. Thus, calculating the weighted average for installation of LEC technology retrofit on all of these large IC engines results in a 2.8 g/bhp-hr limit.

Comment: In their letter of October 25, 2002, INGAA commented that the additional data we collected includes data on 27 lean-burn engines and the data indicate that the average retrofit LEC technology level is 2.7 g/bhp-hr for 2-stroke engines, which represent the bulk of the engine horsepower in the NO_X SIP Call area. In addition, INGAA commented that the data reported on the IC engines retrofit with LEC have a number of problems, including scarcity of before-and-after tests on the same engine, and the absence of data on load or other operating conditions of the tested engines. The INGAA also commented that the vendor references we cited indicate that the retrofit LEC technology is intended to result in emissions to meet a 3 g/bhp-hr limit.

Response: We agree that test data cited by INGAA and the vendor estimates indicate that the average retrofit LEC technology level is in the 2.7 to 3.0 g/bhp-hr range. We also note that these comments are fairly consistent with a November 20, 2000 letter to the OTC from two pipeline companies which recommended a limit of no less than 3.0 g/bhp-hr, with an alternative standard of no more than 80 percent reduction. This range is also consistent with the available test data for large engines in the NO_X SIP Call area which indicate an average value of 2.8 g/bhp-hr.

As INGAA points out, there is some uncertainty in the test data due, for example, to lack of data on operating load in some cases. In addition, there is some uncertainty because of the lack of data for all engine models. Due to this uncertainty, we believe it is appropriate to consider a minor adjustment to the control level suggested by the test data. The difference between selecting a 2.8 value (suggested primarily by the test data) or a 3.0 value (suggested by some pipeline companies and vendor comments) for the controlled emission rate is very small, only a 1 percent difference. That is, the two values result in either an 82 percent or 83 percent control level, assuming a 16.8 g/bhp-hr uncontrolled value. Thus, while our analysis of the test data indicates a 2.8 value is reasonable, in view of the recommended 3.0 level from some industry and vendor comments, and considering the uncertainties in the data and the small difference in the resultant control level, we believe it is appropriate to select the upper range of the control levels proposed, namely 3.0 g/bhp-hr.

(3) Level of NO_X control to assume for budget calculation.

Comment: In the proposed rule we invited comment on how many of the large natural gas-fired IC engines are from lean-burn operation and how many are from rich-burn. The INGAA commented that 156 of the 168 large engines listed in the NO_X SIP Call Inventory that have Standard Industrial Classification codes associated with the natural gas transmission industry are lean-burn models, with one exception. For the purposes of calculating the IC engine portion of the NO_X SIP Call State budgets, INGAA recommended that we should assume that all the large natural gas-fired stationary engines in the inventory are lean burn. Comments from the State of Indiana indicated there are no large, rich-burn engines in the State.

Response: As pointed out by the commenters, the vast majority of large IC engines in the NO_X SIP Call inventory are natural gas-fired lean-burn engines. Furthermore, the emission inventory does not contain sufficient detail to determine exactly which engines are lean burn and which are not. For these reasons, we agree with the comment that it is reasonable to assume that all the large natural gas stationary engines in the inventory are lean burn for the purposes of calculating the IC engine portion of the NO_X SIP Call State budgets.

[31] "Stationary Reciprocating Internal Combustion Engines: Updated Information on NO_X Emissions and Control Techniques," EC/R Incorporated, September 1, 2000, page 4–5 (Docket No. OAR–2001–0008, Item No. XII–K–43).

[32] Docket No. OAR–2001–0008, Item No. XII–D–24.

Comment: As discussed above, we received comments on the uncontrolled and controlled levels for natural gas-fired engines. Several commenters recommended no more than 70 percent reduction, based primarily on permit data. One State recommended 90 percent reduction.

Response: The percent reduction determination is based primarily on two factors—the uncontrolled and controlled levels—which are discussed above. We reviewed information submitted by commenters and collected additional data in response to concerns raised by commenters. Considering all of the available data, we have determined that the appropriate uncontrolled and controlled values are 16.8 and 3.0, respectively. As a result, we believe that application of highly cost-effective controls on large natural gas-fired IC engines will achieve, on average, an 82 percent reduction. Therefore, 82 percent is used for purposes of calculating this portion of the NO_X SIP Call budget.

b. Flexibility/Averaging

Comment: Several commenters noted that the response of IC engines to retrofit NO_X controls is highly variable and that the average NO_X reduction used to calculate the NO_X SIP Call budgets is not necessarily the level that all large engines can achieve. Because of this variability, these commenters suggest that State air agencies should assign NO_X reductions to the owners or operators of IC engines, but not attempt a uniform definition of the required control technology, or specification of a single compliance limit. The commenters suggest that we include language in the final rule stating that we recommend, and will approve, SIPs which provide that owners or operators of large engines in the NO_X SIP Call inventory develop company-specific compliance plans to demonstrate achievement of NO_X reductions. In addition to describing the standards for emissions reductions averaging in the final rule, commenters suggested that we issue a guidance letter to the States urging them to provide flexibility for IC engines and explaining how to do that. The industry lists a number of advantages to the company compliance plan approach to meeting the engine NO_X reductions in the NO_X SIP Call Rule:

- Engine owners and operators would accept enforceable and verifiable measures to control engines to meet assigned NO_X SIP Call reductions.
- Based on the company compliance plans, States would be able to clearly demonstrate to us their compliance with Phase II of the NO_X SIP Call.
- The EPA, States, and regulated companies would not have to work through the technical confusion of definitions of lean-burn and rich-burn engines, and whether individual engines could in fact achieve certain control levels with a prescribed control technology.
- Compliance with NO_X SIP Call requirements could be achieved with minimum impacts on cost, natural gas capacity, and operational reliability.

One pipeline company stated that we should encourage States implementing the engine portion of the NO_X SIP Call to focus primarily on the population of large engines which emitted more than 1 ton per day during the 1995 ozone season and which formed the basis for our calculation of the desired emissions reductions. Retrofitting this population of engines is more feasible and is the most cost-effective method for achieving reductions due to economies achieved by controlling larger sources.

Response: We addressed this issue in a guidance memorandum dated August 22, 2002. As discussed in the reference memorandum,[33] where States choose to regulate large IC engines, we encourage the States to allow owners and operators of large IC engines the flexibility to achieve the NO_X tons/season reductions by selecting from among a variety of technologies or a combination of technologies applied to various sizes and types of IC engines. Flexibility would be helpful as companies take into account that individual engines or engine models may respond differently to control equipment. That is, while certain controls are known to have a specific average control effectiveness for an engine population, some individual engines that install the controls would be expected to be above and some below that average control level, simply because it is an average. Although the issue of flexibility does not affect the setting of the NO_X SIP Call budget, it is an important issue as States take steps to meet their NO_X SIP Call requirements.

During the SIP development process, the States may establish an NO_X tons/season emissions decrease target for individual companies and then provide the companies with the opportunity to develop a plan that would achieve the needed emissions reductions. The companies may select from a variety of control measures to apply at their various emission units in the State, or portion of the State, affected under the NO_X SIP Call. These control measures would be adopted as part of the SIP and must yield enforceable and demonstrable reductions equal to the NO_X tons/season reductions required by the State. What is important from our perspective is that the State, through a SIP revision, demonstrate that all the control measures contained in the SIP are collectively adequate to provide for compliance with the State's NO_X budget during the 2007 ozone season.

c. New Source Review (NSR) Exclusion

Comment: Some commenters stated that the final rule should provide an exemption from NSR regulations for IC engines that install NO_X controls for compliance with the NO_X SIP Call. According to the commenters, installation of the required emission controls will likely result in increases in emissions of carbon monoxide (CO) and/or volatile organic compounds (VOC); the resulting emission increases could exceed the "significant'' levels for CO or VOC, thereby subjecting those facilities to either prevention of significant deterioration (PSD) or nonattainment NSR permit requirements; and, this would increase the compliance costs. Pipeline industry comments request that we expressly state in our final remand response that installing controls on IC engines to meet NO_X SIP Call requirements will not trigger NSR for NO_X under the "actual-to-potential'' test. Commenters also request that we state that installing retrofit controls is an "environmentally beneficial'' action that qualifies for an NSR exclusion for any collateral increases of other criteria pollutants.

Response: As discussed in the earlier referenced memorandum,[34] where sources choose to install combustion modification technology to reduce emissions of NO_X at natural gas-fired lean-burn IC engines, we believe this action should be considered by permitting authorities for exclusion from major NSR as a pollution control project. Further, the memo indicates that, unless information regarding a specific case indicates otherwise, installation of combustion modification technology for the purpose of reducing NO_X emissions at natural gas-fired lean-burn IC engines can be presumed, by its nature, to be environmentally beneficial. We recently stated our intent to modify

[33] August 22, 2002 memo from Lydia Wegman to EPA Regional Air Directors providing guidance on issues related to stationary IC engines and the NO_X SIP Call (Docket No. OAR–2001–0008, Item No. XII–C–115).

[34] August 22, 2002 memo from Lydia Wegman to EPA Regional Air Directors providing guidance on issues related to stationary IC engines and the NO_X SIP Call (Docket No. OAR–2001–0008, Item No. XII–C–115).

the "actual to potential'' test.[35] In most cases, we believe that LEC retrofit technology will not increase emissions of CO or VOC to the extent that NSR is triggered; in many cases, emissions of CO and VOC will decrease with the installation of LEC technology (see RTC document for details). Thus, we believe that the permit process will not hamper efforts to install controls.

d. Early Reductions

Comments: Industry comments recommend that we provide specific guidance in the final rule that directs States to recognize emissions reductions that companies have made since 1995, and that companies should be allowed credit for emissions reductions achieved since 1995 for determining compliance with their portion of the States' emissions reductions required to meet the emissions budgets.

Response: We addressed this issue in the above mentioned guidance memorandum. As discussed in the memo, we agree that creditable reductions with respect to the NO_X SIP Call may include emission controls in place during or prior to 1995, as well as after 1995 for the large engines. In addition, States generally may use emissions reductions achieved after 1995 at the smaller engines as part of their NO_X SIP Call budget demonstration.

e. Presumptive Technology

Comment: Because of the variability of gas pipeline engines in the NO_X SIP Call area, industry commenters suggest that State air agencies should assign NO_X reductions to the owners or operators of IC engines, but not attempt a uniform definition of the required control technology, or specification of a single compliance limit. There is significant variability both in the pre-controlled emission levels of lean-burn engines and in the response of any particular engine to the retrofit installation of LEC technology.

Response: As suggested, we have dropped from the final rulemaking the definition of LEC retrofit technology and the presumption of NO_X reduction effectiveness. The definition and presumption are not necessary to establish the NO_X budget. Nevertheless, we believe that, on average, LEC technology achieves an 82 percent reduction from uncontrolled emissions.

f. Monitoring

Comment: Industry comments recommended that we should specify in the final rule the types of monitoring that will be acceptable.

Response: We addressed this issue in the August 22, 2002 guidance memorandum. As discussed in the memo, acceptable monitoring is not limited to those monitoring methods such as continuous or predictive emissions measurement systems that rely on automated data collection from instruments. Non-automated monitoring may provide a reasonable assurance of compliance for IC engines provided such periodic monitoring is sufficient to yield reliable data for the relevant time periods determined by the emission standard.

g. Emission Factors for 2- and 4-Stroke Engines

Comment: Some commenters asked us to use separate emission factors for 2- and 4-stroke engines.

Response: As described above, we examined "uncontrolled'' emissions from 2- and 4-stroke engines separately and concluded that the data support the 16.8 value we proposed. We also examined the available "controlled'' data separately for 2- and 4-stroke engines. Test data for the large IC engines in the NO_X SIP Call area indicate controlled levels of 2.3 and 2.5, respectively, for the 2- and 4-stroke engines. Assuming 85 percent of the engines in the NO_X SIP Call area are 2-stroke, the weighted average of the 2.3 and 2.5 values is 2.3. Thus, because the 2-stroke engines dominate the NO_X SIP Call inventory and the controlled value for the 4-stroke engines is nearly identical, there is no benefit from using separate emission factors. Furthermore, our emission inventory is not detailed enough to identify which engines are 2- or 4-stroke engines; thus, we need to use an average value to represent the combined population of large, lean-burn engines. We believe the difference between the two values is relatively small, there is a great deal of overlap, some key industry reports also use a single value, the available data for 2- and 4-stroke engines support the value we proposed, control techniques are the same, and we have already subdivided the category of IC engines. For these reasons, we have chosen not to further subdivide the IC engines category.

C. What Is Our Response to the Court Decision on Georgia and Missouri?

In today's final action, we are finalizing our inclusion of only certain portions of Georgia and Missouri in the NO_X SIP Call and revising their statewide budgets to reflect our inclusion of only sources in the fine grid parts of both States.

As stated in the final NO_X SIP Call Rule, air pollution travels across county and State lines and it is essential for State governments and air pollution control agencies to cooperate to solve the problem. Ozone transport is a regional problem and we believe that NO_X emissions reductions across the region in amounts achievable by cost-effective controls is a reasonable step to take to mitigate ozone nonattainment in downwind States (63 FR 57362). These emissions reductions, in combination with other measures, will enable attainment and maintenance of the 1-hour ozone NAAQs in the OTAG region.[36] Since the problem is a regional one, we believe that all States in the NO_X SIP Call area must cooperate to solve the problem.

By way of background, we took final action on October 27, 1998, in the NO_X SIP Call Rule, to prohibit those amounts of NO_X emissions which significantly contribute to downwind nonattainment. *See,* NO_X SIP Call Rule, 63 FR 57356. We determined the amount of emissions that significantly contribute to downwind nonattainment by evaluating:

(1) The overall nature of the ozone problem (*i.e.* "collective contribution''); (2) the extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas; (3) the ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems; and (4) the availability of highly cost-effective control measures for upwind emissions. (63 FR 57376, October 27, 1998).

As part of our analyses of the air quality factors we considered the OTAG modeling and our State-specific modeling. Id. at 57384.

In its modeling, OTAG used grids drawn across most of the eastern half of the United States. The "fine grid'' has grid cells of approximately 12 kilometers on each side (144 square kilometers). The "coarse grid'' extends beyond the perimeter of the fine grid and has cells with 36 kilometer

[35] In the **Federal Register** on December 31, 2002, EPA codified/finalized the Pollution Prevention Project exclusion. In Table 2, Environmentally Beneficial Pollution Control Projects, LEC for IC engines is mentioned. However, for the present time, the regulatory changes generally only affect States with delegation authority to implement the Federal PSD program which became effective on March 3, 2003. For States continuing to implement their existing programs for another 2 to 3 years, the August 22, 2002 guidance memo mentioned above, is appropriate.

[36] OTAG Policy Paper approved by the Policy Group on December 4, 1995.

resolution. The fine grid includes the area encompassed by a box with the following geographic coordinates as shown in Figure 1, below: Southwest Corner: 92 degrees West longitude, 32 degrees North latitude; Northeast Corner: 69.5 degrees West longitude, 44 degrees North latitude (OTAG Final Report, chapter 2). The OTAG could not include the entire Eastern U.S. within the fine grid because of computer hardware constraints.

It is important to note that there were three key factors directly related to air quality which OTAG considered in determining the location of the fine grid-coarse grid line.[37] (OTAG Technical Supporting Document, chapter 2, pg. 6; also available at the following Web site: *http://www.epa.gov/ttn/naaqs/ozone/rto/otag/finalrpt/*). Specifically, the fine grid-coarse grid line was drawn to:

(1) Include within the fine grid as many of the 1-hour ozone nonattainment problem areas as possible and still stay within the computer and model run time constraints, (2) avoid dividing any individual major urban area between the fine grid and coarse grid, and (3) be located along an area of relatively low emissions density. As a result, the fine grid-coarse grid line did not track State boundaries, and Missouri and Georgia were among several States that were split between the fine and coarse grids. Eastern Missouri and northern Georgia were in the fine grid while western Missouri and southern Georgia were in the coarse grid.

The analysis OTAG conducted found that the emission controls they examined, when modeled in the entire coarse grid (*i.e.,* all States and portions of States in the OTAG region that are in the coarse grid) had little impact on high 1-hour ozone levels in the downwind ozone problem areas of the fine grid.[38] The OTAG also concluded from its modeling that the closer an upwind area is to the downwind area, the greater the benefits in the downwind area from controls in the upwind area.

Examining the 2007 Base Case[39] NO_X emissions for Georgia indicates that the amount of NO_X emissions per square mile in the fine grid portion of the State is over 60 percent greater than in the coarse grid part. In Missouri, the amount of NO_X emissions per square mile in the fine grid portion of the State is more than 100 percent greater (*i.e.,* more than double) than in the coarse grid part.

A number of parties, including certain States as well as industry and labor groups challenged the NO_X SIP Call Rule. Specifically, Georgia and Missouri industry petitioners claimed that our record supported inclusion of only eastern Missouri and northern Georgia as contributing significantly to downwind nonattainment. The DC Circuit Court upheld our finding of significant contribution for almost all jurisdictions covered by the NO_X SIP Call, but vacated and remanded our inclusion of Georgia and Missouri. *Michigan* v. *EPA,* 213 F. 3d 663 (DC Cir. 2000), cert. denied, 121 S. Ct. 1225 (2001) (*Michigan*). The Court found that the NO_X budgets for these States "not only encompass the whole state but are calculated on the basis of hypothesized cutbacks from areas that have *not* been shown to have made significant contributions.'' Id. at 684 (emphasis in original). The Court also found that "*EPA must first establish that there is a measurable contribution*'' from the coarse grid portion of the State before holding the coarse grid portion of the State responsible for the significant contribution of downwind ozone nonattainment in another state. Id. at 683–84 (emphasis in original).

Subsequently, we made revisions to the NO_X SIP Call Rule emissions budgets in the Technical Amendments Rulemakings (64 FR 26298, May 14, 1999); (65 FR 11222, March 2, 2000). A group of Missouri Utilities and the City of Independence, Missouri challenged our budget for the State of Missouri and requested the Court to vacate the entire budget under both the 1-hour and 8-hour ozone standards. In its decision, the Court found "it prudent to vacate and remand the TAs [technical amendments] insofar as they include[d] a budget for Missouri under any ozone standard.'' *Appalachian Power Company* v. *EPA,* 251 F. 3d 1026, 1041 (2001). The Court also found that "[w]here the agency's own data inculpate part of a state and not another, EPA should honor the resulting findings.'' Id. at 1040.

In response to the Court's decisions, we issued the February 22, 2002 rule proposing to include only fine grid parts of Georgia and Missouri in the NO_X SIP Call. We explained that the Court in *Michigan* did not call into question our "proposition that the fine grid portion of each State should be considered to make a significant contribution downwind.'' (67 FR 8413).

We stated that based on OTAG's modeling and recommendations, the technical support documents for the NO_X SIP Call rulemaking, and emissions data, we believed that emissions in the fine grid parts of Georgia and Missouri comprise a measurable or material portion of the entire State's significant contribution to downwind nonattainment. In addition, we explained that we had performed State-by-State modeling for Georgia and Missouri as part of the final NO_X SIP Call rulemaking. The results of this modeling showed that emissions in both Georgia and Missouri make a significant contribution to nonattainment in other States. Moreover, we explained that the Court pointed out that the fine grid portion of each State lies closer to downwind nonattainment areas. *Michigan* v. *EPA,* 213 F. 3d at 683.

We further explained that for purposes of determining budgets for the fine grid portion, we believed that OTAG modeling should be used with an adjustment for counties that straddle the line separating the fine grid and coarse grid. We also explained that we would base our overall NO_X emissions budgets on all counties which lie wholly contained in the fine grid, as a result of the difficulties and uncertainties associated with accurately dividing the fine and coarse grid for individual counties. Counties that straddle the fine grid-coarse grid line or which are completely within the coarse grid would be excluded from the budget calculations for Georgia and Missouri. As a result, we proposed to revise the NO_X budgets for Georgia and Missouri to include only the fine grid portions of these States.

In response to our proposal, several commenters asserted that our inclusion of the fine grid portions of the States of Georgia and Missouri was not supported by reliable data in light of the Court's ruling in *Michigan* and requested additional air quality modeling for these portions. A couple of commenters submitted air quality modeling and one commenter requested reconsideration of our inclusion of sources that lie "just inside the fine grid.'' Other commenters argued that no NO_X SIP Call exists for the States of Georgia and Missouri in light of the Court's holdings in *Michigan* and *Appalachian Power* (Technical Amendments Case). They further argued that the Agency must make independent findings of significant contribution for both eastern Missouri and northern Georgia, respectively. One commenter also contended that we could not base our findings on existing data but must

[37] In addition to these three factors, OTAG considered three other factors in establishing the geographic resolution, overall size, and the extent of the fine grid. These other factors dealt with the computer limitations and the resolution of available model inputs.

[38] The OTAG recommendation on Major Modeling/Air Quality Conclusions approved by the Policy Group, June 3, 1997 (62 FR 60318, appendix B, November 7, 1997).

[39] The 2007 Base Case includes all control measures required by the CAA.

consider new circumstances and any changes in air quality since promulgation of the NO_X SIP Call Rule. Another commenter requested that we not exclude sources in any county that partially lies within the coarse grid area in the affected States.

Under today's final rulemaking, we are finalizing our proposal to include the fine grid portions of Georgia and Missouri as contributing significantly to downwind nonattainment. We believe this is consistent with the Court's pronouncements in *Michigan.* Specifically, the Court found that "[t]he fine grid modeling of *parts* of Missouri and Georgia showed emissions in the aggregate meeting the EPA's threshold 'contribution' criteria.'' Michigan, 213 F.3d at 683 (emphasis in original). The Court also found that it was "no mere techno-fortuity that the fine grid included enough of Missouri to include the city of St. Louis and enough of Georgia to include Atlanta: [because] the fine grid portions of both states are closest to other nonattainment areas, such as Chicago and Birmingham, and generally higher ozone density.'' *Id.*

We see no reason to revise the existing determination that sources in the fine grid parts of Georgia and Missouri contribute significantly to downwind nonattainment. As explained in our proposal, the basis for our determination continues to be: (1) The results of our State-by-State modeling; (2) the relatively high amount of NO_X emissions per square mile in the fine grid portions of each State; and (3) the closeness of the fine grid portions of each State to downwind nonattainment areas compared to the coarse grid portions (67 FR 8414).

Additionally, we note that Georgia and Missouri industry petitioners maintained, as we believe, that there was record support for inclusion of emissions from the eastern half of Missouri and the northern-two thirds of Georgia as contributing to downwind ozone problems. As the Court stated, "[a]ccordingly, they say the NO_X Budget for Missouri and Georgia should be based solely on those emissions.'' *Michigan* 213 F.3d at 684. We have also evaluated the modeling submitted by one commenter and we find that this modeling does not refute our conclusion that sources in the fine grid portions of Georgia and Missouri contribute significantly to downwind nonattainment, as discussed below.

Accordingly, consistent with the Court's finding in *Michigan,* we have revised the NO_X emissions budgets for Georgia and Missouri to include only the fine grid portions of these States. The counties that are included in the calculation of NO_X budgets for each of these States are listed in Table 1.

TABLE 1.—FINE GRID COUNTIES IN GEORGIA AND MISSOURI

Georgia:
Baldwin Co
Banks Co
Barrow Co
Bartow Co
Bibb Co
Bleckley Co
Bulloch Co
Burke Co
Butts Co
Candler Co
Carroll Co
Catoosa Co
Chattahoochee Co
Chattooga Co
Cherokee Co
Clarke Co
Clayton Co
Cobb Co
Columbia Co
Coweta Co
Crawford Co
Dade Co
Dawson Co
De Kalb Co
Dooly Co
Douglas Co
Effingham Co
Elbert Co
Emanuel Co
Evans Co
Fannin Co
Fayette Co
Floyd Co
Forsyth Co
Franklin Co
Fulton Co
Gilmer Co
Glascock Co
Gordon Co
Greene Co
Gwinnett Co
Habersham Co
Hall Co
Hancock Co
Haralson Co
Harris Co
Hart Co
Heard Co
Henry Co
Houston Co
Jackson Co
Jasper Co
Jefferson Co
Jenkins Co
Johnson Co
Jones Co
Lamar Co
Laurens Co
Lincoln Co
Lumpkin Co
McDuffie Co
Macon Co
Madison Co
Marion Co
Meriwether Co
Monroe Co
Morgan Co
Murray Co
Muscogee Co
Newton Co
Oconee Co
Oglethorpe Co
Paulding Co
Peach Co
Pickens Co
Pike Co
Polk Co
Pulaski Co
Putnam Co
Rabun Co
Richmond Co
Rockdale Co
Schley Co
Screven Co
Spalding Co
Stephens Co
Talbot Co
Taliaferro Co
Taylor Co
Towns Co
Treutlen Co
Troup Co
Twiggs Co
Union Co
Upson Co
Walker Co
Walton Co
Warren Co
Washington Co
White Co
Whitfield Co
Wilkes Co
Wilkinson Co
Missouri:
Bollinger Co
Butler Co
Cape Girardeau Co
Carter Co
Clark Co
Crawford Co
Dent Co
Dunklin Co
Franklin Co
Gasconade Co
Iron Co
Jefferson Co
Lewis Co
Lincoln Co
Madison Co
Marion Co
Mississippi Co
Montgomery Co
New Madrid Co
Oregon Co
Pemiscot Co
Perry Co
Pike Co
Ralls Co
Reynolds Co
Ripley Co
St. Charles Co
St. Genevieve Co
St. Francois Co
St. Louis Co
St. Louis City
Scott Co
Shannon Co
Stoddard Co
Warren Co
Washington Co
Wayne Co

We are not making a finding today as to whether sources in the coarse grid portions of Georgia and/or Missouri make a measurable or material part of the significant contribution of each of these States, respectively. In addition, apart from our findings relating to the NO_X SIP Call, a State may, of course, assess the in-State impacts of NO_X emissions from its coarse grid area, and impose additional NO_X reductions, beyond the NO_X SIP Call requirements in the fine grid, as necessary to demonstrate attainment or maintenance of the ozone NAAQS in the State.

Comment: Several commenters supported our inclusion of the fine grid portions of Missouri and Georgia. One commenter requested that we not exclude sources within any county that partially lies within the coarse grid area in the affected States.

Response: Today's action is in response to the court's decision that vacated our inclusion of the entire States of Georgia and Missouri. *Michigan* v. *EPA*, 213 F.3d 663. (DC Cir. 2000), *cert. denied*, 121 S. Ct. 1225 (2001) (*Michigan*). "*EPA must first establish that there is a measurable contribution''* from the coarse grid portion of the State before holding the coarse grid portion responsible for the significant contribution of downwind ozone nonattainment in another state. Id. at 683–84 (emphasis in original).

As explained in our February 22, 2002 proposal, "because of difficulties and uncertainties with accurately dividing emissions between the fine and coarse grid of individual counties for the purpose of setting overall NO_X emissions budgets, we believe that the calculation of the emissions budgets should be based on all counties which are wholly contained within the fine grid.'' (67 FR 8415). We believe this is consistent with the Court's ruling. Thus, we are finalizing the budgets for Georgia and Missouri to include only those counties that lie wholly within the fine grid portions of both States as described above.

Comment: One commenter requested the reconsideration of our inclusion of sources that are "just inside the fine grid.'' This commenter based its request on modeling showing that sources in Georgia south of 32.67 degrees latitude do not significantly contribute to nonattainment ozone areas in downwind States.

Response: We have evaluated the modeling submitted by this commenter and found that the modeling does not refute the overall conclusions we have drawn concerning the impacts of NO_X emissions in the relevant geographic areas. The commenter quantified the contribution from those emissions in Georgia south of 32.67 degrees latitude (*i.e.*, southern Georgia) by modeling the four OTAG episodes with emissions in southern Georgia removed (*i.e.*, zero-out). The results of this modeling, as presented by the commenter, suggest that emissions in southern Georgia contribute less than 2 parts per billion (ppb) to the peak daily 1-hour ozone in 1-hour nonattainment areas outside of Georgia in each of the four episodes. In view of these results, the commenter contends that the contribution from southern Georgia to all downwind nonattainment areas is not significant since the contribution is less than the 2 ppb screening criteria used by EPA in the NO_X SIP Call to identify those upwind State-to-downwind nonattainment area linkages that were clearly not significant. However, the commenter misinterpreted the definition of EPA's 2 ppb screening criteria by limiting the analysis of contribution to just the episode peak concentration in the downwind areas. By doing so, the contractor did not consider or present any data to evaluate the contribution from southern Georgia to other ozone exceedances (*i.e.*, less than the peak value but exceeding the NAAQS) predicted in each downwind area. For example, southern Georgia may not impact the predicted episode peak for the 1-hour ozone standard in Birmingham by 2 ppb, but southern Georgia could have contributed at least 2 ppb to one or more of the other 88 exceedances in Birmingham. Unfortunately, the commenter did not provide any data to permit an examination of the contribution of emissions from southern Georgia to all exceedances in downwind nonattainment areas. Thus, the comment that southern Georgia does not significantly contribute to downwind nonattainment because they did not examine all contributions above 2 ppb.

Thus, to the extent that the sources are modeled by the commenter in a county that falls within the fine grid part of Georgia, we do not believe we should reconsider its inclusion in the NO_X SIP Call.

Comment: Several commenters stated that our inclusion of portions of the State of Georgia was not supported by reliable data and sound science especially in light of *Michigan*, "that remanded and vacated in its entirety [the inclusion of whole states of Georgia and Missouri],'' due to "EPA's unsupportable determination of significant contribution.'' Several commenters also stated that we had failed to provide data to support the inclusion of portions of the State of Georgia that are within the fine grid. Another commenter argued that we had failed to provide information to support inclusion of affected sources in Georgia.

Response: In *Michigan*, the DC Circuit Court held that [t]he fine grid modeling of parts of Missouri and Georgia showed emissions in the aggregate meeting the EPA's threshold contribution criteria.'' *Michigan*, 213 F.3d at 683 (emphasis in original). The Court noted that "EPA's explanation and technique make clear that emissions from the fine grid areas may have been the sole source of the finding.'' *Id.*

The Court also found that it was "no mere techno-fortuity that the fine grid included enough of Missouri to include the city of St. Louis and enough of Georgia to include Atlanta: the[se] fine grid portions of both states are closest to other nonattainment areas, such as Chicago and Birmingham, and generally higher ozone density.'' *Id.* However, the Court vacated and remanded the NO_X SIP Call budgets for the States of Georgia and Missouri finding that the budgets "not only encompass the whole state but are calculated on the basis of hypothesized cutbacks from areas that have *not* been shown to have made significant contributions.'' Id at 684. (emphasis in original). The Court further held that "EPA must first establish that there is a measurable contribution'' from the coarse grid portion of the State before holding the coarse grid portion of the State responsible for the significant contribution of downwind ozone nonattainment in another State. *Id.* In *Appalachian Power Company* v. *EPA*, 251 F. 3d 1026, 1040–1 (2001), the Court found that "insofar as the TAs [technical amendments] include a statewide Missouri emission budget they are unlawful under *Michigan*.''

Thus, the Court did not call into question the proposition that the fine grid portions of Georgia and Missouri should be considered as making a significant contribution to downwind nonattainment. We also note that Georgia and Missouri industry petitioners maintained that, as we believe, there was record support for inclusion of emissions from the eastern half of Missouri and the northern-two thirds of Georgia as contributing to downwind ozone problems. *Michigan*, 213 F. 3d at 681.

In addition, in the NO_X SIP Call Rule, we found that "[s]ources that are closer to the nonattainment area tend to have much larger effects on the air quality than sources that are far away.'' (63 FR 25919.) Further, OTAG's technical findings and recommendations concluded that areas located in the fine grid should receive additional controls because they contribute to ozone in other areas within the fine grid.

Today's rulemaking finalizes our revision of the budgets for Georgia and Missouri to reflect the Court's pronouncements in *Michigan*. This is also consistent with OTAG's recommendations and findings. We have revised neither our existing determination nor our bases for the determination that sources in the fine grid portion of Georgia and Missouri are contributing significantly to downwind nonattainment. We are revising the NO_X budgets for Georgia and Missouri to reflect the inclusion of only the sources that are within the fine grid portions of both States. Accordingly, we also continue to rely on the Technical Support Document and Notice of Data Availability which are the underlying documents for the NO_X SIP Call Rule.

Comment: One commenter argued that the Court vacated our determination of significant contribution for all of Missouri in *Michigan*, and therefore, we no longer have a basis for including any portion of Missouri in the NO_X SIP Call. The commenter also argued that we made no significant contribution finding for eastern Missouri but rather based our findings on emissions from the whole State.

Response: We disagree with the comment. As stated elsewhere in this rule, with respect to the fine grid parts of Georgia and Missouri, the Court found that "the fine grid modeling of parts of Missouri and Georgia showed emissions in the aggregate meeting the EPA's threshold contribution criteria.'' *Michigan*, 213 F.3d. at 683. We also note that Georgia and Missouri industry petitioners maintained that there was record support for inclusion of emissions from the eastern half of Missouri and the northern-two thirds of Georgia as contributing to downwind ozone problems. *Id.*, at 681. The OTAG's recommendations and findings concluded that areas located in the fine grid should receive additional controls because they contribute to ozone in other areas within the fine grid. In addition, our modeling showed that emissions in both Georgia and Missouri make a significant contribution to nonattainment in other areas. Therefore, we believe there is record support for inclusion of eastern Missouri.

Comment: One commenter argued that as a result of the vacatur in *Michigan*, we have to justify the inclusion of eastern Missouri in the NO_X SIP Call taking into consideration facts in existence at the time of our proposal.

Response: We disagree. As stated earlier, the Court found that the modeling showed that emissions from the fine grid portions of the States of Georgia and Missouri met EPA's "threshold 'contribution' criteria.'' The Court also let stand OTAG's modeling analyses (except with respect to Wisconsin). Thus, the inclusion of eastern Missouri accords with the Court pronouncements on the fine grid/coarse grid.

In today's rulemaking, we see no reason to revise the existing determination that sources in the fine grid parts of Missouri contribute significantly to nonattainment downwind. The basis for this determination continues to be: (1) The results of our State-by-State modeling; (2) the relatively high amount of NO_X emissions per square mile in the fine grid portions of the State; and (3) the closeness of the fine grid portions of the State to downwind nonattainment areas compared to the coarse grid part.

Comment: One commenter stated that it was erroneous to continue using data that was 4 years old as our basis for the inclusion of eastern Missouri in the NO_X SIP Call in light of data showing that areas receiving measurable contributions from Missouri sources are now in attainment of the 1-hour ozone standards.

Response: We disagree with the comment that downwind ozone nonattainment areas have achieved attainment of the 1-hour ozone standards. More specifically, Chicago has not yet attained the 1-hour ozone standard. Chicago's attainment demonstration relies, in part, on implementation of Missouri's statewide NO_X rule, approved by EPA into the SIP. The NOX SIP Call reductions in Missouri are needed for Chicago to attain/maintain the 1-hour standard.

Although the attainment plan was approved, we believe it is important to point out that there are inherent uncertainties in the plan, including hourly emission estimates and emissions growth projections. Further, without the NO_X SIP Call, Missouri may come under increased pressure to relax the existing State rule, which could jeopardize attainment in Chicago. Additionally, the SIP-approved State rule has not yet been implemented and was, in fact, recently revised by the State.

The reductions are highly cost effective and would also help offset emissions from a number of large sources locating upwind of St. Louis and avoid very costly local controls in the future.

We disagree that a new emissions inventory is necessary that takes into account Missouri's statewide NO_X rule and other post-1998 CAA rules. Because SIPs are constantly changing, it is impractical to revise emission inventories and modeling analyses each time changes are made. For example, the NO_X limits the commenter cites have since been revised by the State and are yet to be approved by EPA.

Further, completing the NO_X SIP Call in Missouri is an equitable approach. It would be inequitable to use 2003 air quality analysis for Missouri but to hold other NO_X SIP Call States to the 1998 analysis. It should also be noted that we intend to review the NO_X SIP Call Rule and will make adjustments if necessary (63 FR 57428).

This program is the single most important measure to reduce interstate pollution in the short term. Reductions of NO_X emissions from the program will enhance the protection of public health for over 100 million people in the eastern half of the United States—including people in Missouri. It is a centerpiece of the clean air plans for many cities, including the Chicago area.

Comments: Another commenter stated that the current State of Missouri control regulations would achieve greater NO_X emissions and greater improvements than the NO_X SIP Call.

Response: We disagree. Missouri adopted and, in December 2000, we approved a statewide NO_X rule which requires emissions reductions in the eastern third of the State and lesser reductions in the remainder of the State for large EGUs. While we approved this rule because it helped address the ozone nonattainment issue in St Louis, we did not find that this rule addressed the significant transport of NO_X to other areas that we had identified in the NO_X SIP Call. Revisions to the statewide NO_X rule were adopted on April 24, 2003 and were submitted as a SIP revision on September 18, 2003.

Both the SIP-approved statewide NO_X rule and the revisions to the rule submitted to EPA would achieve less NO_X emissions reductions than implementation of the NO_X SIP Call. Missouri's current and proposed revised NO_X rules are less stringent than the NO_X SIP Call requirements. The emissions reductions under the NO_X SIP Call are greater by about 20 percent statewide and 40 percent in the fine grid compared to the SIP-approved Missouri rule. The NO_X SIP Call also offers the advantages of a cap and trade program, including certainty of emissions reductions; the State rules have no emissions cap. While the current State rule and the SIP revisions may accomplish reductions similar to those under the NO_X SIP Call in the short-term, without an emissions cap there is no assurance that the required reductions will continue in the long-term.

Reductions are more effective in preventing interstate transport to key downwind areas under the NO_X SIP Call as they must occur in the eastern part of Missouri and trading is not allowed between eastern and western Missouri EGUs. The Missouri rules spread the requirement for NO_X reductions throughout the entire State. Thus, the emissions reductions are not focused in the geographical area of interest.

The NO_X SIP Call budget also includes reductions in emissions from large cement kilns, industrial boilers, and stationary IC engines. The NO_X SIP Call would allow fewer emissions statewide, as shown in Table 2 below.

TABLE 2.—COMPARISON OF OZONE REDUCTIONS IN THE NO_X SIP CALL AND THE MISSOURI STATEWIDE RULE

EGU emissions (tons per ozone season)	Fine grid	Statewide
Actual 2001 Emissions	30,872	60,102
NO_X SIP Call	13,400 cap	37,600 [a] in 2001 [b c]
MO current SIP-approved rule	23,100 in 2001 [c]	46,900 in 2001 [c]
MO revised rule	19,100 in 2001d [c]	49,600 in 2001 [c]

[a] Assuming Missouri's current SIP-approved rule remains effective in the coarse grid (reductions from rule are included in the attainment demonstrations for St. Louis and Chicago).

[b] The table only compares EGU emissions; the NO_X SIP Call requires 2,900 tons additional NO_X reductions due to controls on cement, industrial boilers and engines in the fine grid.

[c] Estimated emissions based on actual 2001 heat input; emissions after 2001 would be higher as the State rule has no cap.

Further, we informed the State of some problem areas in their recent rule revisions. In addition to the issues above, there are other SIP-approvability concerns with the Missouri statewide rule which make it likely that the rule would have to undergo further revision. These include concerns about the credibility of early reduction credits which appear not to be actual surplus.

D. What Are We Finalizing for Alabama and Michigan in Light of the Court Decision on Georgia and Missouri?

We calculated Alabama's and Michigan's budgets in the same manner as we did for Georgia and Missouri, as described above. While no petitioners raised any issues concerning the inclusion of only parts of Alabama and Michigan in the NO_X SIP Call, the Court's reasoning regarding Georgia and Missouri applies equally to Alabama and Michigan. Based on the information in the record, we revised the NO_X budgets for Alabama and Michigan to reflect reductions only in the fine grid portions of these States.[40] Again, like Georgia and Missouri, we see no reason to disturb the determination that sources in the fine grid contribute significantly to nonattainment downwind; the fine grid portions of both Alabama and Michigan are closer to downwind 1-hour ozone nonattainment areas than the coarse grid parts of these States. Also, the amount of NO_X emissions per square mile in the fine grid portion of Alabama is nearly 60 percent greater than in the coarse grid part; and in Michigan the fine grid NO_X emissions per square mile are more than 500 percent greater than emissions per square mile in the coarse grid portion of the State. Counties in Michigan and Alabama which straddle the fine grid-coarse grid are excluded from the budget calculations as described above for Georgia and Missouri. We believe this approach is consistent with the holding in *Michigan* concerning Georgia and Missouri and is justified as provided above.[41]

The counties in Alabama and Michigan that are included in the calculation of NO_X budgets for each of these States are listed in Table 3.

TABLE 3.—FINE GRID COUNTIES IN ALABAMA AND MICHIGAN

Alabama:
- Autauga Co
- Bibb Co
- Blount Co
- Calhoun Co
- Chambers Co
- Cherokee Co
- Chilton Co
- Clay Co
- Cleburne Co
- Colbert Co
- Coosa Co
- Cullman Co
- Dallas Co
- De Kalb Co

TABLE 3.—FINE GRID COUNTIES IN ALABAMA AND MICHIGAN—Continued

- Elmore Co
- Etowah Co
- Fayette Co
- Franklin Co
- Greene Co
- Hale Co
- Jackson Co
- Jefferson Co
- Lamar Co
- Lauderdale Co
- Lawrence Co
- Lee Co
- Limestone Co
- Macon Co
- Madison Co
- Marion Co
- Marshall Co
- Morgan Co
- Perry Co
- Pickens Co
- Randolph Co
- Russell Co
- St. Clair Co
- Shelby Co
- Sumter Co
- Talladega Co
- Tallapoosa Co
- Tuscaloosa Co
- Walker Co
- Winston Co

Michigan:
- Allegan Co
- Barry Co
- Bay Co
- Berrien Co
- Branch Co
- Calhoun Co
- Cass Co
- Clinton Co
- Eaton Co
- Genesee Co
- Gratiot Co
- Hillsdale Co
- Ingham Co
- Ionia Co
- Isabella Co
- Jackson Co
- Kalamazoo Co

[40] Both Georgia and Missouri submitted Phase I SIPs which included only the fine grid portion of the States.

[41] Pursuant to the court's order lifting the stay of the SIP submission obligation, the 20 States, including Alabama, Michigan, and the District of Columbia, were required to submit SIPs in response to the NO_X SIP Call by October 30, 2000. As discussed above, in letters dated April 11, 2000 to State Governors, we informed the States that remained subject to the NO_X SIP Call that they could choose to submit SIPs meeting only the Phase I emissions budget for each State. With respect to Alabama and Michigan, we also provided that they could choose to submit SIPs that address emissions only in the fine grid portion of the State. Alabama and Michigan submitted Phase I SIPs which included only the fine grid portion of the States.

TABLE 3.—FINE GRID COUNTIES IN ALABAMA AND MICHIGAN—Continued

Kent Co
Lapeer Co
Lenawee Co
Livingston Co
Macomb Co
Mecosta Co
Midland Co
Monroe Co
Montcalm Co
Muskegon Co
Newaygo Co
Oakland Co
Oceana Co
Ottawa Co
Saginaw Co
St. Clair Co
St. Joseph Co
Sanilac Co
Shiawassee Co
Tuscola Co
Van Buren Co
Washtenaw Co
Wayne Co

E. What Modifications Are Being Made to the NO_X Emissions Budgets?

In today's final action, in a change from the proposed rule, we are excluding certain small cogeneration units from the definition of EGU. All other cogeneration units and other non-acid rain units will remain as EGUs. As a result, it makes sense to require States to include in their Phase II SIPs the anticipated emissions reductions from non-Acid Rain units. However, since, as discussed below, States seem to have already included non-Acid Rain units in the Phase I SIPs, today's action concerning the EGU definition will have little or no effect on State budgets and required reductions.

We are also finalizing technical changes to the EGU definition in the NO_X SIP Call to make it consistent with the definition of EGU used in the Section 126 Rule. Since the EGU definition establishes the dividing line between the EGU and non-EGU categories, the changes to the EGU definition result in corresponding changes to the non-EGU definition in the NO_X SIP Call, which make it consistent with the non-EGU definition in the Section 126 Rule. Today's action concerning these definitions does not result in any specific revisions to the budgets established under the final NO_X SIP Call and the Technical Amendments.

We are recalculating the budgets to reflect a control level of 82 percent for the natural gas-fired lean-burn IC engines. For the other IC engine subcategories (diesel and dual fuel) we are using 90 percent control, as proposed.

We are calculating the budgets for Georgia, Missouri, Alabama, and Michigan assuming controls in all counties that are fully located in the fine grid, as discussed in sections II.C. and II.D. The partial State budgets for Georgia, Missouri, Alabama, and Michigan in today's action are calculated using IC engine control, as well as the definition of EGUs as described above.

Our budgets are shown in Tables 4 and 5. For States that are required to submit Phase I SIPs, Table 6 shows the Phase I and final budgets and the incremental difference between the two budgets. We are requiring States that have submitted SIPs that meet only the Phase I budget to supplement their control plans with rules that will meet the Phase II increment.

The budget numbers in Tables 4 and 5 are based on the NO_X SIP Call emission inventory as revised in the "Technical Amendment to the Finding of Significant Contribution and Rulemaking for Certain States for Purposes of Reducing Regional Transport of Ozone,'' which was published on March 2, 2000. The EPA first published minor changes to the NO_X SIP Call emission inventory in a Technical Amendment published May 14, 1999, in response to comments on the 2007 baseline sub-inventory in the NO_X SIP Call published October 27, 1998. After the first Technical Amendment was published, EPA received further comments stating that the baseline sub-inventory contained errors. In response to these comments, EPA published the second Technical Amendment on March 2, 2000, in which changes were made to the baseline inventory and budgets for the NO_X SIP Call for submitted data which was determined to be technically justified.

In some cases, States have made minor corrections to their NO_X SIP Call emission inventory as part of their response to the NO_X SIP Call requirements. States making corrections include, for example, Kentucky, Illinois, and Indiana. The EPA has evaluated these corrected emission inventories on a case-by-case basis and, as appropriate, approved the corrections as part of the rulemaking on the State's NO_X SIP Call submittal. Today's rulemaking on the Phase II NO_X SIP Call requirements is based on the corrections to the NO_X SIP Call emission inventory published March 2, 2000 and does not take into account these corrections made in the individual State rulemaking actions. Furthermore, additional corrections may be made in the future to certain State emission inventories due, for example, to the change in the definition of EGU. As stated in the NO_X SIP Call, "[t]he control measures that the State chooses to require will become the enforceable mechanism under the NO_X SIP Call'' (63 FR 57426, October 27, 1998). The reader should refer to both this final rule and individual rulemaking actions on each State's SIP revision in response to the NO_X SIP Call for more information.

In cases where the Phase I budget in a State's approved SIP revision differs from the EPA budget, due to changes in sources approved by EPA, the State is required to achieve the incremental Phase II reductions shown in Table 6 in order to meet the full NO_X SIP Call. In cases where the State has voluntarily submitted, and EPA has approved Phase I SIPs with budgets more stringent than required by EPA, the State is required to achieve the final budgets shown in Table 6.

TABLE 4.—STATE EMISSIONS BUDGETS AND PERCENT REDUCTION

[tons/season]

State	Final base	Final budget	Tons reduced	Percent reduction
Connecticut	46,015	42,850	3,165	7
Delaware	23,797	22,862	935	4
District of Columbia	6,471	6,657	−186	−3
Illinois	368,870	271,091	97,779	27
Indiana	340,654	230,381	110,273	32
Kentucky	237,413	162,519	74,894	32
Maryland	103,476	81,947	21,529	21
Massachusetts	87,095	84,848	2,247	3
New Jersey	105,489	96,876	8,613	8
New York	255,658	240,322	15,336	6

TABLE 4.—STATE EMISSIONS BUDGETS AND PERCENT REDUCTION—Continued

[tons/season]

State	Final base	Final budget	Tons reduced	Percent reduction
North Carolina	224,696	165,306	59,390	26
Ohio	373,222	249,541	123,681	33
Pennsylvania	345,203	257,928	87,275	25
Rhode Island	9,463	9,378	85	1
South Carolina	152,805	123,496	29,309	19
Tennessee	256,765	198,286	58,479	23
Virginia	210,786	180,521	30,265	14
West Virginia	176,699	83,921	92,778	53

TABLE 5.—STATE EMISSIONS BUDGETS AND PERCENT REDUCTION

[tons/season]

State	Final base	Final budget	Tons reduced	Percent reduction
Georgia	209,914	150,656	59,258	28
Missouri	92,697	61,406	31,291	34
Alabama	169,156	119,827	49,329	29
Michigan	245,929	190,908	55,021	22

TABLE 6—COMPARISON OF PHASE I AND PHASE II STATE NO_X BUDGETS COMPARISON

[tons/season]

State	Phase I budget	Final budget	Phase II incremental difference
Alabama	124,795	119,827	4,968
Connecticut	42,891	42,850	41
Delaware	23,522	22,862	660
District of Columbia	6,658	6,657	1
Illinois	278,146	271,091	7,055
Indiana	234,625	230,381	4,244
Kentucky	165,075	162,519	2,556
Maryland	82,727	81,947	780
Massachusetts	85,871	84,848	1,023
Michigan	191,941	190,908	1,033
New Jersey	95,882	96,876	−994
New York	241,981	240,322	1,659
North Carolina	171,332	165,306	6,026
Ohio	252,282	249,541	2,741
Pennsylvania	268,158	257,928	10,230
Rhode Island	9,570	9,378	192
South Carolina	127,756	123,496	4,260
Tennessee	201,163	198,286	2,877
Virginia	186,689	180,521	6,168
West Virginia	85,045	83,921	1,124

F. How Will the Compliance Supplement Pools Be Handled?

The compliance supplement pool (CSP) is a pool of allowances that can be used in the beginning of the program to provide affected sources additional compliance flexibility. The CSP was created to address concerns raised by commenters on the NO_X SIP Call proposal regarding electric reliability during the initial years of the program. In the NO_X SIP Call Rule, the CSP may be used in the years 2003 and 2004 (*see* 63 FR 57428–57430, October 27, 1998, for further discussion of the CSP). In *Michigan,* the DC Circuit Court ruled that May 31, 2004, rather than May 1, 2003, is the date by which sources must install controls to comply with the NO_X SIP Call. Consequently, to be consistent with the original 2-year window specified in the NO_X SIP Call in which we allowed the CSP allowances to be used, we are finalizing an extension of the time that allowances from the CSP can be used from September 30, 2004 to September 30, 2005 for sources with a May 31, 2004 compliance date, and to September 30, 2008 for sources with a May 1, 2007 compliance date. We are also including CSPs for Georgia and Missouri. As under the original NO_X SIP Call, Georgia and Missouri may distribute the allowances in their respective pools either based on early reductions, directly to sources based on a demonstrated need, or by some combination of the two methods. (For a more complete discussion of how CSP allowances may be distributed under the NO_X SIP Call, *see* 63 FR 57429.) The allowances from Georgia's and Missouri's CSPs may be used to account for emissions during the 2007 and 2008 ozone seasons, the first 2 years' ozone seasons that sources in those States are required to comply.

We are not changing the individual State CSP values that were finalized in the March 2, 2000 technical corrections to the emission budgets (65 FR 11222) with the exception of Alabama, Georgia, Michigan, Missouri, and Wisconsin. Changing the State CSPs to reflect the State budget changes made in this action would result in minimal impacts on the size of any State's CSP. Therefore, we have decided to maintain the CSPs at the levels determined in the March 2, 2000 technical amendment (with the exception of Alabama, Georgia, Michigan, Missouri, and Wisconsin).

Since required reductions in Georgia, Missouri, Alabama, and Michigan finalized under today's final rule are less than the required reductions of the October 27, 1998 NO_X SIP Call reflecting full State emissions budgets, we are making corresponding decreases to the CSPs for the portion of each State that is still subject to the NO_X SIP Call. We have calculated the partial-State CSPs by prorating the size of the full-State CSP by the ratio of the reductions that we are finalizing for the partial State to the reductions that we required in the March 2, 2000 Technical Amendment (65 FR 11222). However, even though we are finalizing an 82 percent reduction requirement from large natural gas-fired IC engines, to be consistent with the way the CSP was calculated in the other States, we assumed a 90 percent reduction from all large IC engines for purposes of calculating the CSP. In addition, since Wisconsin is not being required to make reductions at this time, Wisconsin is no longer receiving a share of the CSP. (Wisconsin's original CSP was 6,920 tons.) For these reasons, the total CSP is now less than 200,000 tons. The revised CSPs for Georgia, Missouri, Alabama, and Michigan are shown in Table 7.

TABLE 7.—COMPLIANCE SUPPLEMENT POOLS (CSP)

	Full State tons reduced (from March 2, 2000 FR)	Partial State tons reduced with 90 percent IC engine control	Full State low	Partial State CSP with 90 percent IC engine control
GA	63,582	57,623	11,440	10,728
MO	62,242	31,291	11,199	5,630
AL	64,954	49,806	11,687	8,962
MI	63,118	55,064	11,356	9,907

One commenter (EL Paso Corporation, OAR–2001–0008, XII–D–10), commented that IC engines should be allowed to receive reductions from the CSP. The commenter asserts that we have failed to recognize that the CSP contains NO_X allocations generated by IC engines. The commenter also claims that because IC engines will also have to be retrofitted to comply with the NO_X SIP Call they could also have reliability problems and, therefore, should be able to receive allowances from the CSP.

Under the NO_X SIP Call, the CSP is limited to use by the large boilers and turbines that are in the NO_X Budget Trading Program. Because IC engines are not in the NO_X Budget Trading Program, they are not eligible to receive allowances from the CSP. States have two options for making the pool available to sources in the trading program. One option is to distribute some or all of the pool to sources that generate early reductions during ozone seasons prior to May 1, 2003. The second option is to run a public process to provide tons to sources that demonstrate a need for a compliance extension. The pool was created to help that group of sources meet compliance deadlines without jeopardizing electric reliability. It was not created to address reliability problems in other sectors.

G. Will the EGU Budget Changes Affect the States Included in the Three-State Memorandum of Understanding?

In February 1999, Connecticut, Massachusetts, Rhode Island, and EPA signed a Memorandum of Understanding (the three-State MOU). The three-State MOU redistributed Connecticut, Massachusetts, and Rhode Island's EGU emissions budgets to minimize the size differential between their EGU budgets under the NO_X SIP Call and Phase III of the OTC NO_X Budget program. It also reallocated the three States' CSPs.

Under the three-State MOU, Connecticut, Massachusetts, and Rhode Island would collectively be meeting their NO_X SIP Call reduction responsibilities because the budget redistribution did not result in a higher combined overall EGU budget for the three States. We took action to implement the three-State MOU and concurrently published proposed and direct final rules on September 15, 1999 (64 FR 50036 and 49987). We subsequently withdrew the direct final rule on November 1, 1999 due to the receipt of adverse comment (64 FR 58792). The EGU budgets in today's action will not affect the EGU budgets for Connecticut, Massachusetts, and Rhode Island that we proposed in response to the three-State MOU. We did not finalize the proposal to act on the three State MOU. Instead, we proposed to approve the three States' NO_X SIP Call SIP submittals, with budgets that reflected the three-State MOU, as collectively meeting their NO_X SIP Call budgets. We did not receive any comments on the proposed approval of these three State's SIPs and finalized approval of them on December 27, 2000.

H. How Does the Term "Budget'' Relate to Conformity Budgets?

We wish to clarify that the use of the term "budget'' in this action does not refer to the transportation conformity rule's use of the term "motor vehicle emissions budget,'' defined at 40 CFR 93.101. The budgets finalized today do not set budgets for specific ozone nonattainment areas for the purposes of transportation conformity. Transportation conformity budgets cannot be tied directly to the NO_X SIP Call budgets because the latter are for all or a large part of the State and the former are nonattainment-area-specific. For nonattainment or maintenance areas in a State covered by the NO_X SIP Call, transportation conformity budgets must reflect the mobile source controls assumed in the NO_X SIP Call budgets to the extent that the attainment SIP ultimately relies upon those controls.

I. How Will Partial-State Trading Be Administered?

In the final NO_X SIP Call, we offered to administer a multi-State NO_X Budget Trading Program for States affected by the NO_X SIP Call. In today's action, we are including only partial State budgets for Alabama, Georgia, Michigan, and Missouri. Therefore, we will administer a trading program for the NO_X SIP Call region that, for these four States, includes only the portion of the States we are including in the NO_X SIP Call. In the final NO_X SIP Call, as well as the January 18, 2000 final rulemaking on the original eight Section 126 petitions, we authorized sources in States affected by either the NO_X SIP Call or the Section 126 rulemaking to trade with each other through the mechanisms of the NO_X Budget Trading Program provided certain criteria were met. These criteria included that States must be subject to the NO_X SIP Call and that States must meet the emission control level under the final rule for the NO_X SIP Call. The justification for allowing trading across States is the test of significant contribution which underlies both the Section 126 rulemaking and the NO_X SIP Call. Therefore, at this time, only sources in the portions of the States for which a finding of significant contribution has been made and budgets have been established are allowed to participate in trading with sources in States which are subject to either the NO_X SIP Call or the Section 126 rulemaking.

1. How Will Flow Control Be Handled for Georgia and Missouri?

The NO_X SIP Call (63 FR 57356) includes a limitation (referred to as "flow control'') on the use of banked allowances for compliance with the requirement to hold allowances covering emissions from affected units.[42] In the NO_X SIP Call, we noted that banking of allowances may inhibit or prohibit achievement of the desired emissions budget in a given [ozone] season since the use of banked allowances for compliance for a specific ozone season may result in total emissions for affected units exceeding the trading budget for that ozone season (63 FR 25902, 25935; May 11, 1998). The trading budget reflects the emissions reductions mandated, and found to be highly cost effective, under the NO_X SIP Call in order to prevent significant contribution to nonattainment in downwind States. Flow control addresses the potential problem caused by banking by continuing to allow unlimited banking of unused allowances but discouraging the "excessive use'' of banked allowances for compliance. Id.; *see also* 63 FR 57473.

Flow control discourages the excessive use of banked allowances by discounting the use of banked allowances for compliance over a specified threshold. This threshold was set at 10 percent in the NO_X SIP Call and applies to the entire NO_X SIP Call region. The number of banked allowances held in all allowance tracking system (ATS) accounts under the trading program is tabulated when each ozone season is completed to determine what percentage banked allowances comprise of the total multi-State trading budget for the next ozone season. If this percentage is greater than 10 percent, flow control is triggered, and a withdrawal ratio is established for that next ozone season. The withdrawal ratio is calculated by dividing 10 percent of the total multi-state trading program budget for that next ozone season by the total number of banked allowances at the end of the completed ozone season. The ratio is then applied to each ATS compliance account that holds banked allowances at the end of that next ozone season. A unit can use banked allowances for compliance without restriction (*i.e.*, on a one-allowance-to-one ton basis) in an amount not exceeding the amount in the unit's compliance account times the withdrawal ratio. Banked allowances used for compliance in an amount exceeding that determined using the withdrawal ratio must be used on a two-allowances-for-one ton basis.

The NO_X SIP Call provided that flow control provisions apply starting in the second year of the NO_X SIP Call program. (The first ozone season in which flow control applies and can be triggered is referred to as the "flow control date.'') Specifically, the NO_X SIP Call established May 1, 2003 as the commencement date for the NO_X SIP Call program and required the flow control provisions to apply starting in the second year (*i.e.*, 2004). *See* 40 CFR 51.121(b)(1)(ii) and (b)(2)(ii)(E). Subsequent to the initial NO_X SIP Call rulemaking, the D.C. Circuit delayed the commencement date for the NO_X SIP Call program to May 31, 2004, and so the second year of the program—and the required flow control date—for State programs beginning in 2004 became 2005. While the regulations (§ 51.121 and part 96) were not revised, we have implemented the new flow control date through the notice and comment rulemakings for approval of the SIPs. We have approved rules under the NO_X SIP Call for 17 States and the District of Columbia. The approved rules provide for a flow control date of 2004 or 2005,[43] and, as a practical matter the earliest date that flow control can be triggered in any of these States and the District of Columbia is 2005.[44]

It is our general intent to treat affected units in Georgia and Missouri in essentially the same manner as affected units under Phase I of the NO_X SIP Call. Once Georgia and Missouri submit SIPs in accordance with today's rule, we will review these SIPs in light of our general intent. As we did in the case of the SIPs submitted by States under Phase I of the NO_X SIP Call, we will address, in the context of reviewing Georgia's and Missouri's SIPs, such issues as the flow control provisions and the flow control date and are not revising the flow control date in § 51.121 and part 96.

However, we note that if the flow control provisions in the initial NO_X SIP Call Rule were applied to Georgia and Missouri, potential problems could arise because the units in those States would have a flow control date, *i.e.*, the second year (2008) of those States' programs, that is 3 years later than the effective 2005 flow control date for units in States in Phase I of the NO_X SIP Call. We will consider and resolve these potential problems when we review Georgia's and Missouri's SIPs rather than in today's rule. In order to provide guidance to Georgia and Missouri in the development of their SIPs, we are discussing below these potential problems.

The potential problems in applying the flow control provision in § 51.121

[42] Banked allowances are those allowances that are not used in the ozone season for which they are allocated and that are therefore carried into the next ozone season. Allowances from the CSP are considered banked at the start of the second year of the program. *See* 40 CFR 51.121(b)(2)(ii)(D).

[43] In approving trading program rules for Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, and Rhode Island, we approved flow control dates of 2004 based on the initial NO_X SIP Call Rule, under which the program started May 1, 2003. (We note that we erroneously approved 2005 as the flow control date for Pennsylvania, whose program also begins in 2003.) After the Court established May 31, 2004 as the commencement date for the NO_X SIP Call program, we approved 2005 as the flow control date for States (*i.e.*, Alabama, Illinois, Indiana, Kentucky, North Carolina, South Carolina, Tennessee, and West Virginia) whose programs begin in 2004. We also approved NO_X SIP Call rules for two States (Ohio and Virginia) on the condition that a 2005 flow control date be adopted.

[44] Although we approved several State programs with a 2004 flow control date (see footnote number 43), 2005 is the earliest year that flow control is likely to be triggered for those States. For 2004, the calculation for triggering flow control is the total number of banked allowances in accounts as of December 1, 2003 (*i.e.*, only the unused allowances allocated for 2003 plus the CSP allowances for those States with programs beginning in 2003) divided by the total trading budgets for the States with programs in effect in 2004 (*i.e.*, virtually all States in the NO_X SIP Call region). Because, for this calculation for 2004, the number of States reflected in the numerator is so much smaller than the number of States reflected in the denominator, 2005 is effectively the flow control date for all States whose programs begin in 2003.

and part 96 to Georgia and Missouri are as follows. Allowing 2008 to be the flow control date in Georgia (or Missouri) could result in an unfair advantage for units in that State over units in other States with an effective 2005 flow control date. Specifically, for the 2007 ozone season when the Georgia (or Missouri) programs begin, banked allowances held for Georgia (or Missouri) units or by Georgia (or Missouri) companies as of November 30, 2006 could be a contributing factor for triggering flow control in 2007 for all other States with programs that are in effect. If Georgia (or Missouri) units were to help trigger flow control in 2007 but would not be subject to the flow control limitation on use of banked allowances in 2007, this would give Georgia (or Missouri) units an unfair advantage over units in the other States.

Further, should a 2008 flow control date be approved for Georgia (or Missouri), this would allow some companies to circumvent the earlier flow control dates established by other States. A company with affected units in both Georgia (or Missouri) and a State with an effective 2005 flow control date would be particularly advantaged in this regard. Such a company could circumvent the earlier flow control date by exchanging banked allowances held for its units in the State with the 2005 flow control date for 2007 allowances held for its units in Georgia (or Missouri). All of these banked allowances could be used in Georgia (or Missouri) in 2007 without application of flow control. Moreover, a company with only units in States with earlier flow control dates could also circumvent, to some extent, the flow control provisions of those States. To the extent that the latter company could purchase 2007 allowances and sell banked allowances, it could also avoid the application of the flow control limitation in 2007. In short, allowing a 2008 flow control date for Georgia (or Missouri) would allow erosion of the effectiveness of flow control for States with an effective 2005 flow control date and would give an unfair advantage to some companies.

We believe these potential problems might be avoided if, under Georgia's and Missouri's SIPs, flow control is effective starting in the first year (2007) of their programs while CSP allowances for those States continue to be treated as banked allowances starting in the second year (2008) of their programs. This approach would appear to prevent companies from being able to circumvent the effective 2005 flow control dates in other States' programs since banked allowances—whether held by units or companies in Georgia or Missouri or in other States—would be subject to flow control in 2007. Transferring banked allowances to Georgia or Missouri units or companies would not avoid flow control if it is triggered.

It also appears that applying flow control in the first year of the program in Georgia and Missouri would not disadvantage units and companies in Georgia and Missouri with regard to their CSP allowances. The NO_X SIP Call established that the CSP could be used in the first 2 years of a State's trading program without the application of flow control to the CSP allowances in the first year. Under the approach discussed above, the allowances from Georgia's and Missouri's CSPs (like the CSPs for other States) would be available for use in the first and second years (2007 and 2008 for Georgia and Missouri). Because the CSP allowances would not be considered banked until 2008, these allowances could be used in the first year of the program (2007) without being affected by flow control. Thus, the Georgia and Missouri CSP allowances could be used in 2007 without limit regardless of whether flow control is triggered at the end of the 2006 ozone season and could not trigger flow control at the end of 2007.

As noted above, today's rule does not establish a flow control date for Georgia and Missouri. Instead, we are indicating how we intend to address this issue when we review the Georgia and Missouri SIPs, and we will consider, in conducting those reviews, the approach discussed above and any other approach that is proposed for addressing the issue.

J. What Is the Phase II SIP Submittal Date?

In today's action, we are setting a date for States to submit SIPs meeting the Phase II NO_X budgets and the partial State budgets for Georgia and Missouri. We believe that an adequate timeframe for SIP submittal is 12 months from signature date of this rulemaking. We believe that this schedule will allow adequate time for States to promulgate rules, and for sources affected by a State's Phase II NO_X strategy and by Georgia and Missouri's NO_X strategy to comply with the regulations by the dates in this action. Please see section K, below, for a discussion of the compliance dates.

Comment: Several commenters contend that the range of proposed SIP submittal dates (*i.e.*, 6 months to a year from final promulgation of this rulemaking, but no later than April 1, 2003) does not allow enough time for States to develop a SIP. They noted that this is due to the fact that the proposal was published on February 22, 2002 and the comment period was scheduled to end on April 15, 2002, and that the final rule would not be promulgated in time to allow adequate time for States to complete their rulemaking processes. These commenters fell into several categories based on their recommendation for a SIP submittal date: (1) EPA is not allowing enough time for SIP submittal; (2) EPA should set a SIP submittal date 12 months from the date of final promulgation of this rule; (3) EPA should allow more than 12 months for States to submit SIPs; and (4) EPA should allow 18 months for SIP submittal as authorized in section 110(k)(5).

Response: After considering these comments, we are requiring that SIP revisions be submitted within 12 months after the date of signature of this final rule. We believe this is adequate time for States to submit SIP revisions reflecting the reductions required by this phase of the NO_X SIP Call. In response to the court decision in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), *cert. denied,* 121 S. Ct. 1225 (2001), we divided the NO_X SIP Call into two phases—Phase I which accounted for 90 percent of the total reductions required by the NO_X SIP Call, and Phase II which will achieve approximately 10 percent of the total reductions required by the NO_X SIP Call. Thus, because Phase II of the NO_X SIP Call requires relatively smaller NO_X emissions reductions and because it applies to a much smaller subset of sources, we believe that 12 months is adequate time for States to develop and submit the required SIP revisions. In addition, as earlier stated, this action is being taken under section 110(k)(5) which requires SIP revisions within a specified period but "not to exceed 18 months'' after a finding of inadequacy by the Agency.

Initially we had allowed States 12 months for submittal of SIPs meeting the full NO_X SIP Call, with September 30, 1999 as the submission date. On May 25, 1999, in response to a request by States challenging the NO_X SIP Call, the DC Circuit issued a stay of the SIP submission deadline pending further order of the Court. *Michigan,* 213 F. 3d 663 (DC Cir. 2000), *cert. denied*, 121 S. Ct. 1225 (2001) (May 25, 1999 order granting stay in part). Subsequently, we filed a motion on April 11, 2000, requesting the court to lift the stay of the SIP submission date and on June 22, 2000, the court lifted the stay and established October 30, 2000, as the new SIP submission date. Thus, by setting this submission date, the Court recognized the 12-month submission schedule required in the NO_X SIP Call.

In setting this timeframe, we also recognize that the proposed NO_X SIP submittal date of 6 months to 1 year from final promulgation of this rulemaking, but no later than April 1, 2003, is no longer appropriate due to the February 22, 2002 publication date of the proposed rule. We are also aware that some States have lengthy rulemaking processes that may require longer than 12 months for full adoption of regulations. However, States have the ability to set their rulemaking procedures and can provide adequate mechanisms to adopt regulations to address interstate transport. Many States already have emergency or other shortened procedures in place in order to bypass regular rulemaking procedures in certain circumstances. We also note that some States have already adopted SIPs that comply fully with the NO_X SIP Call.

Moreover, we note that States that fail to submit SIPs within 12 months are not precluded from submitting plans after that date. Areas will not be subject to mandatory sanctions under section 179 of the CAA until 18 months after we find that the State failed to submit a plan in response to the NO_X SIP Call. Furthermore, if the State makes a late submission, our approval of that program would serve to replace any Federal plan that may have taken effect in the interim. We note that States can submit draft plans (*i.e.*, plans that have not completed the final steps in the State administrative process) for parallel processing. *See* 47 FR 2703 (June 23, 1982). While this type of submission may not preclude a finding of failure to submit, it can help ensure that the State program is approved as a SIP revision and as a replacement for any promulgated Federal implementation plan in the most expeditious manner. Also, as we did for the Phase I NO_X SIP submittals, the EPA Regional Offices and Headquarters will work closely with the States to ensure that approvability issues are quickly resolved in order to allow SIPs to be submitted as expeditiously as possible.[45] (Section II.J, OAR–2001–0008, comments XII–D–28, XII–D–29).

K. What Are the Phase II Compliance Dates?

We are setting a Phase II compliance date of May 1, 2007. This date is 24 months after the SIP submittal date plus the days until the next ozone season begins. However, sources already controlled in an approved Phase I SIP are required to meet the compliance date stipulated in that SIP, including non-Acid Rain EGUs and any cogeneration units that were previously classified as EGUs and whose classification changed to non-EGUs under today's rule.

In this section, it is important to note that although compliance dates are discussed for certain EGUs, non-EGUs, and IC engines, States may choose to control other sources. As stated in the original NO_X SIP Call:

> States are not constrained to adopt measures that mirror the measures EPA used in calculating the budgets. In fact, EPA believes that many control measures not on the list relied upon to develop EPA's proposed budgets are reasonable—especially those, like enhanced vehicle inspection and maintenance programs, that yield both NO_X and VOC emissions reductions. Thus, one State may choose to primarily achieve emissions reductions from stationary sources while another State may focus emission reductions from the mobile source sector. (63 FR 57378, October 27, 1998).

1. How Are We Handling Non-Acid Rain EGUs and Any Cogeneration Units That Were Previously Classified as EGUs and Whose Classification Changed to Non-EGUs Under Today's Rule?

We proposed a compliance date of May 31, 2004 (or, if later, the date on which the source commences operation) for all Phase II EGUs and non-EGUs in Alabama, Connecticut, District of Columbia, Delaware, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, and West Virginia. We also proposed a compliance date of May 1, 2005 (or, if later, the date on which the source commences operation) for all sources in Georgia and Missouri. The compliance dates mark the beginning of the periods during which units in the trading program must hold at least enough NO_X allowances to cover their ozone season NO_X emissions.

The proposed compliance date of May 31, 2004 (or, if later, the date on which the source commences operation) was designed to provide Phase II EGUs and non-EGUs a little over 12 months after the deadline for State submission of Phase II SIPs covering such units to install any necessary emission controls. In today's rule, we are finalizing a deadline of April 1, 2005 for submission of Phase II SIPs. However, we believe that for all of the States (except Georgia and Missouri, which are addressed separately below), non-Acid Rain EGUs and any cogeneration units that were previously classified as EGUs and whose classification changed to non-EGUs under today's rule were included in the Phase I SIPs that were already submitted.[46] Several States (*i.e.*, Connecticut, District of Columbia, Delaware, Massachusetts, Maryland, New Jersey, New York, Pennsylvania, and Rhode Island) have submitted SIPs that cover non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule, as well as Phase I EGUs and non-EGUs, and require compliance with the allowance holding requirement starting May 1, 2003 (or, if later, the date on which the source commences operation). The remaining States other than Georgia and Missouri (*i.e.*, Alabama, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, South Carolina, Tennessee, Virginia, and West Virginia) have submitted SIPs that cover non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule, as well as Phase I EGUs and non-EGUs and require compliance starting May 31, 2004 (or, if later, the date on which the source commences operation). The coverage of non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule is reflected both in the applicability provisions in the various SIPs—which provisions cover EGUs and non-EGUs without assuming any non-Acid Rain units or any cogeneration units—and in the State budget demonstrations and allowance allocations—which list the affected units including the non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule. Although, elsewhere in today's final rule, we are revising the definition of EGU and non-EGU, we believe that these revisions will require the reclassification of few, if any, units as EGUs and non-EGUs and will not make any additional units subject to the NO_X

[45] Technical Support Document, "Responses to Significant Comments on the Proposed Finding of Significant Contribution and Rulemaking for Certain States in the OTAG Region for Purposes of Reducing Regional Transport of Ozone,'' Docket No. A–96–56, Item No. VI–C–01, September 1998.

[46] We note that the non-EGU classification of those cogeneration units that have been consistently treated as non-EGUs in the NO_X SIP Call and the Section 126 Rule was not remanded and vacated by the Court, and we maintain that the May 31, 2004 compliance date for such units is not at issue in today's rulemaking. However, even assuming *arguendo* that their compliance date were at issue, there would be no basis for establishing a later compliance date since these units (like, *e.g.*, the non-Acid Rain EGUs) are already subject to the May 31, 2004 date under the Phase I SIPs.

SIP Call. *See* section II.A.4 of this preamble.[47]

Since all Phase II non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule in these States are already subject to a compliance date of May 1, 2003 or May 31, 2004 (or, if later, the date on which the source commences operation), we see no basis for extending the NO_X SIP Call compliance deadline beyond the date stipulated in the Phase I SIPs under which these units are covered. The CAA rests on an "overarching'' principle that the NAAQS be achieved as expeditiously as possible (63 FR 57356, 57449, October 27, 1998). For example, under section 181 of the CAA, the "primary standard attainment date for ozone shall be as expeditiously as practicable but not later than [certain statutorily prescribed attainment dates].'' 42 U.S.C. 7511; *see also* 42 U.S.C. 7502(a)(2)(A). The State trading budgets under the NO_X SIP Call reflect the emissions reductions mandated under the NO_X SIP Call in order to prevent significant contribution to nonattainment in downwind States. Under these circumstances, we believe that the CAA's overarching objective of expeditious as practicable attainment applies to these units.

A number of commenters (including several States that have adopted SIPs with May 31, 2004 compliance dates for non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule) suggested that a compliance date of May 31, 2004 did not provide sources enough time to install emission controls. Some commenters suggested that units should be given 2 years after submittal of SIPs to comply. Several other commenters suggested that a compliance deadline should be set 1,309 days after the required SIP submittal date to be consistent with the DC Circuit's August 30, 2000 order related to compliance dates under the NO_X SIP Call. As explained above, we do not believe it is necessary or appropriate to extend the compliance date beyond May 31, 2004 because the States involved have already adopted rules requiring non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule to comply by that date or earlier. It should also be noted that, even if the units had not already been included in the State's Phase I SIPs, the 1,309-day period used for setting the May 31, 2004 compliance date for Phase I SIPs would not be appropriate for those units. The Court's decision to provide units 1,309 days after submittal of SIPs was based on the amount of time that we provided units to comply with the original NO_X SIP Call, which had a compliance deadline of May 1, 2003. The original NO_X SIP Call required States to make significantly more emissions reductions (*i.e.*, all the reductions that were subsequently designated as either Phase I or Phase II reductions in response to the Court's decision) than the reductions (*i.e.*, only the Phase II reductions for non-Acid Rain EGUs and any cogeneration units whose classification changed from EGUs to non-EGUs under today's rule) addressed here. Greater emissions reductions require the installation of more emission controls, which in turn requires more resources such as boiler-makers and cranes. The analysis that we performed for the proposed Phase II rule shows that less time is required to install emission controls for the smaller number of Phase II units than the significantly larger number of Phase I units in the trading program.

2. What Compliance Date Are We Finalizing for IC Engines and What is the Technical Feasibility of This Date?

We are setting a compliance date for IC engines of May 1, 2007 (or, if later, the date on which the source commences operation). This date is 24 months after the SIP submittal date plus the days until the next ozone season begins.

Comment: Several commenters from the pipeline industry suggest the need to stagger or phase-in the compliance activities over several years. Additional comments from the pipeline industry state that we ignore time needed to get permits; that we assume 160 engines would be off-line in the same winter heating season; and that we failed to consider the problem of having multiple engines at one facility subject to retrofit requirements during the same short compliance timeframe.

Comments from 22 citizen groups recommend the May 2004 and May 2005 dates (or, if later, the date on which the source commences operation), as proposed. One State supports the May 2005 compliance deadline proposed. All other commenters request that we provide more time than was proposed. Another State believes that a minimum of 24 months from the date of final SIP submittals is needed for sources to complete the necessary construction and installation of controls to comply with the Phase II provisions. A third State recommends the compliance date be 1,309 days after the SIP submittal date. Pipeline industry comments generally recommend May 2007 or 36 to 43 months from SIP submittal. These commenters refer to the 1998 NO_X SIP Call Rule which gave 43 months from SIP submittal. Utility group comments also recommend we should apply the same 1,309-day compliance period for the Phase II NO_X SIP Call requirements that applies to sources for the Phase I compliance pursuant to the original NO_X SIP Call Rule schedule.

Response: The pipeline industry has considerable experience with the installation of LEC technology. While there is some evidence that installation of controls on a few engines within 1 year is reasonable, installing controls on many engines in a narrow timeframe is more problematic. As discussed below, we believe that the proposed timeframe of about 13 months should be extended to a minimum of 24 months from the SIP submittal date and the initial compliance date should occur within the ozone season.

We obtained additional information regarding this issue. One manufacturer estimated the time between request for cost proposal and contract to be 2 to 5 months and typically 3 to 4 months. It then takes 4 to 5 months for delivery and an additional 1 month to install and commence operation. This adds up to a total of 7 to 11 months.[48] Another manufacturer estimated the time between cost proposal and contract is 2 to 4 weeks to obtain bids; 2 to 3 months for selection of bids; 12 to 20 weeks for parts delivery to site; and 2 weeks to 1½ months for field installation. Another manufacturer estimated from request for cost bids to shipping of parts takes 6 to 8 months for delivery and an additional 2 to 4 weeks to install and commence operation. This adds up to a total of 6 to 9 months.[49] Information from the Ventura County Air Pollution Control District in California estimated 2 weeks to 1 month to install LEC and the total time estimated from request for cost proposal and commencing operation of LEC was 6 to 9 months. A gas pipeline company, CMS Energy, stated that a compliance schedule of 11 months was easy to meet for one to two engines but would put a stress on the system for 200 engines. Columbia Gas Transmission Corporation installed controls on two engines in Bedford County,

[47] To the extent that the revisions of the EGU and non-EGU definitions have such an impact on any specific units, we will address the matter in connection with our review of the relevant State Phase II SIP provisions.

[48] See Docket No. OAR–2001–0008, Item No. XII–E–01.

[49] See Docket No. OAR–2001–0008, Item No. XII–E–02.

Pennsylvania in 3 days, meeting the 3.0 g/bhp-hr standard set by the State.[50] Thus, there is some agreement that the necessary compliance period for installation of controls on a small number of engines is less than 1 year.

We disagree with the comment that 160 engines would be off-line at the same time. We expect some companies to choose to phase-in installation of the control equipment over a 2-year period (or longer if the companies begin retrofit activities sooner) and that installation activities would occur primarily in the summer along with normally scheduled maintenance activities. Further, as noted below, not all of the potentially affected IC engines should be expected to need LEC retrofits and not in the same timeframe.

In response to Phase II of the NO_X SIP Call, some States may seek emissions reductions from source categories other than IC engines. Other States have already met their NO_X budgets and do not need to further control IC engines for purposes of the NO_X SIP Call. Still other States have met at least a portion of the Phase II NO_X SIP Call reductions due to emissions reductions affecting other source categories contained in their 1-hour ozone nonattainment area plans. This reduces the need to retrofit IC engines in those States.

In many cases, companies may use "early reductions'' achieved at IC engines due to other requirements, such as RACT.[51] For example, many IC engines were previously controlled to meet RACT requirements in many of the NO_X SIP Call States. These emissions reductions help States meet their NO_X budgets and, thus, decrease the amount of additional reductions needed. According to information submitted by INGAA, a 1996–97 survey determined that 245 lean burn engines in the NO_X SIP Call area have LEC.[52] Many engines in the NO_X SIP Call area already have decreased NO_X emissions at rich-burn engines through non-selective catalytic reduction (NSCR).[53] States may choose to credit these reductions instead of requiring new reductions at other engines in order to meet the SIP budget.

Many more NO_X reductions are likely to result from future maximum achievable control technology (MACT) controls at IC engines.[54] These factors also reduce the need to retrofit IC engines in some States.

We agree with industry comments that pipeline companies will phase-in the control equipment over a multi-year timeframe. Some companies may choose to stagger installation of the controls, beginning even before completion of our rulemaking.[55] Stretching out the installation timeframe in this manner would help the companies achieve the results on time. Further, companies might choose to install controls early in some of their engines in a timeframe that coincides with the engine rebuild cycle.[56] In another case, installation of the LEC retrofit kit was estimated to span 3 to 4 weeks and the installation was not expected to impact the normal maintenance interval.[57] These approaches will help reduce the time needed to install the controls.

We believe the industry has demonstrated that multiple engines at compressor stations can be successfully retrofitted over a 24-month timeframe. For example, in Kentucky, the Jefferson Town Compressor Station's RACT compliance plan of April 2000 describes the installation of LEC using a phased approach over a 2-year period. Four engines were retrofitted during the summer of 2001 and the remaining five engines were retrofitted in the summer of 2002. Each engine was expected to be out of service for approximately 6 weeks and, due to heavy demand during the winter heating season, all engines were expected to be operable from October to April. Two additional cases show installation on multiple engines in short time periods. Southern California Gas Company completed testing of one engine in 1995 and installed precombustion chambers on six engines in its Mojave Desert operating area. The conversion of the first unit was completed in October 1995 and the conversion of the sixth unit was completed in November 1996. The engines met the 2.0 g/bhp-hr standard set by the Mojave Air District. Furthermore, as cited in a case study in Vidor, Texas, six engines in the Beaumont/Port Arthur area were retrofitted in the summer of 1999.[58]

As shown below, we also examined historic timeframes allowed by the Congress and various regulatory agencies to achieve compliance with NO_X requirements following State/local rule adoption. These timeframes generally illustrate the successful implementation of past regulatory programs involving the installation of NO_X controls.

In the 1990 Amendments to the CAA, Congress added RACT requirements for major sources of NO_X. All categories of major NO_X sources in certain areas of the nation were required to install RACT as expeditiously as practicable or no later than May 31, 1995. Thus, Congress allowed a maximum of 30 months from the SIP submittal deadline of November 15, 1992 for a much larger number of sources than affected by this rulemaking.

Subsequent to the initial set of NO_X RACT SIP revisions, we approved NO_X RACT SIP submittals in some areas which had been exempt from the requirements. For example, in Dallas, SIP rules required RACT as expeditiously as practicable or 24 months from the State adoption date (rule adopted March 21, 1999). The State of Texas, on December 31, 1997, implemented a requirement for all major NO_X sources in the Houston area to implement RACT; the State adopted a compliance date of November 15, 1999 for this program (22.5 months). In a recent case, the State of Louisiana allowed up to a 3-year period in Baton Rouge, coinciding with their attainment deadline.

For engines subject to RACT limits, the California Air Resources Board guidance document on IC engines recommends final compliance within 2 years of district rule adoption.[59] The guidance states that this time period should be sufficient to evaluate control options, place purchase orders, install equipment, and perform compliance verification testing. The Sacramento Air District in California required compliance within 2 years of rule adoption (June 1995).

Regarding the need to obtain permits, we believe that States will process permits expeditiously, especially those permits associated with pollution control projects. We have specifically encouraged States in a recent memo (see NSR exclusion discussion in section

[50] See *http://www.dieselsupply.com/dscartic.htm* for reprint of article from May 1998 of "American Oil & Gas Reporter.''

[51] Memo from Lydia Wegman, Director, Air Quality Strategies and Standards Division, U.S. EPA to Air Division Directors, U.S. EPA Regions I–V, VII (August 22, 2002), providing guidance on issues related to stationary IC engines and the NO_X SIP Call.

[52] "IC Engine OTAG Questions'' document prepared by INGAA, February 17, 2000. Many of these engines are smaller than the "large'' engines identified in the NO_X SIP Call.

[53] Alpha Gamma memo of June 19, 2002 (Docket No. OAR–2001–0008, Item No. 0917).

[54] See proposed rule at 67 FR 77845.

[55] INGAA letter of July 16, 2002 (Docket No. OAR–2001–0008, Item No. 0918).

[56] A top-end overhaul is generally recommended between 8,000 and 30,000 hours of operation that entails a cylinder head and turbocharger rebuild (see Table 4 from "Technology Characterization: Reciprocating Engines'' prepared by Energy Nexus Group for EPA, 2–02).

[57] GRI 12–98 report "NO_X Control for Two-Cycle Pipeline Reciprocating Engines,'' page 4–11. (Docket No. OAR–2001–0008, Item No. XII–K–24.)

[58] See *http://www.enginuityinc.com.*

[59] "Determination of RACT and BARCT for Stationary Spark-Ignited Internal Combustion Engines,'' California Air Resources Board, November 2001, pg. IV–15. (Docket No. OAR–2001–0008, Item No. XII–K–71.)

II.B.2.c of this final rule) to consider exempting pollution control projects from certain permitting requirements. Further, by moving the compliance date to at least 24 months after the SIP submittal date, we believe that the time needed to revise permits will not adversely affect the compliance schedule.

Further, the CAA contains an overarching principle that downwind areas attain the ozone NAAQS "as expeditiously as practicable.'' [Sections 191(a), 172(a)]. The emissions reductions from today's rulemaking reflect the emissions reductions mandated under the NO_X SIP Call in order to prevent significant contribution to nonattainment in downwind States. Thus, we are setting an implementation date that will assure that the downwind States realize the air quality benefits of NO_X reductions in order to achieve attainment or reasonable further progress toward attainment (63 FR 57449–50).

Although we provided a compliance date of 1,309 days for Phase I sources from the SIP submittal date, we do not believe that a similar compliance period is needed for the sources affected by today's rulemaking. This is because today's rulemaking affects a smaller subset of sources than Phase I sources, and these sources have been aware of the applicability of the NO_X SIP Call since 1998. In addition, as discussed earlier, States are free to choose which sources to regulate in compliance with the NO_X SIP Call requirements. Also, some States have already adopted SIPs that meet the full NO_X SIP Call requirements.

In summary, several factors described above will serve to minimize the number of large IC engines that would need to be scheduled for LEC retrofit. Further, companies that phase-in compliance activities over several years would also reduce the number of IC engines needing LEC retrofit per year. It is important to note that RACT experience shows that companies can install LEC retrofit over a 2-year timeframe, even where multiple engines are located at the same compressor station. In recent RACT compliance time decisions, State/local regulatory agencies generally specified 24-month periods to install controls. The Congress in its 1990 CAA Amendments allowed a maximum of 30 months for all major NO_X sources across the nation to install RACT; this was a much larger task than installation of controls at IC engines in certain States. As a result, we believe that a 2-year period after the SIP submittal due date is adequate for the installation of controls.

Further, because the NO_X SIP Call is directed at emissions during the ozone season, we believe that the initial month where compliance is required should occur during the ozone season. Therefore, the compliance date is May 1, 2007 (or, if later, the date on which the source commences operation).

3. What Compliance Date Are We Finalizing for Georgia and Missouri?

For all sources in Georgia and Missouri, we proposed a compliance date of May 1, 2005 (or, if later, the date on which the source commences operation). This compliance date was based on a proposed SIP submittal deadline of April 1, 2003 and would have provided sources 25 months after SIP submittal to install controls. Based on the April 1, 2005 SIP submittal deadline being finalized in today's final rule, providing sources with 25 months to install controls would result in a compliance deadline of May 1, 2007. Because this would be after the 2006 ozone season, we are finalizing a compliance deadline of May 1, 2007 (or, if later, the date on which the source commences operation). As we explained in the NO_X SIP Call, we believe a 25-month compliance timeframe is reasonable given the amount of controls that need to be installed. If Missouri and/or Georgia elect to control large EGUs under a trading program, we project that the most time-consuming control installation will require installation of two SCRs and one SNCR. We also project that this can be done in 25 months (67 FR 8395).

Several commenters suggested that a May 1, 2005 compliance date was reasonable for Georgia and Missouri if the rule were finalized in time to give States 1 year to develop a regulation and SIPs were due by April 1, 2003. One commenter added that many EGUs will be installing controls before 2005 in order to comply with a State ozone attainment plan. We agree that the proposed compliance deadline was reasonable when it was proposed. However, we are adopting a May 1, 2007 compliance deadline to take into account the delay in finalizing today's rule.

One commenter suggested that providing units in Georgia and Missouri 25 months to comply was not enough time. This commenter provided documentation from an engineering firm suggesting that it would take at least 36 months to install SCR on one unit. The commenter further asserted that it would take even longer to install SCR on two units at a single plant and suggested that Missouri sources be given at least 43 months to install controls. We disagree with this commenter. Many SCR projects have been completed in significantly less time. For instance, a SCR was installed on the AES Somerset Plant in New York in 9 months from contract award to completion. Reliant Energy completed construction of two SCRs on two 900 MW units at their Keystone Plant in Pennsylvania in 46 weeks. Even assuming that the engineering and permitting took a year, this job was completed in less than 24 months. It should also be noted that this job was completed in 2003. This was part of the peak construction period for SCRs under Phase I of the NO_X SIP Call. Projects in Georgia and Missouri, being constructed after the bulk of the SCRs for the NO_X SIP Call have been installed, should have much less competition for resources. The commenter provided no explanation of why this project should take so long when so many other projects have been completed in less time. Furthermore, the NO_X SIP Call provides Missouri with CSP allowances that Missouri may use to address situations when installation cannot be completely finished by the compliance date. It should also be noted that while we believe that the SCRs can be installed within 25 months, if Missouri completes its SIP by December 31, 2005, they will actually have 29 months to install the SCRs. This assumes that the company does not begin any work on the SCRs until after the SIP is finalized. Since the company should have a strong indication as to whether they will need to install the SCRs before the SIP is completed, they will actually have more than 29 months to install the SCRs.

L. What Action Are We Taking on Wisconsin?

In Michigan, the Wisconsin industry petitioners argued that the emissions from Wisconsin do not contribute significantly to nonattainment in any other State. Section 110(a)(2)(D)(i)(I)requires that a State "contribute significantly to nonattainment in * * * any other State'' in order to be included in the challenged NO_X SIP Call. 42 U.S.C. 7410(a)(2)(D)(i)(I). The Court held that "EPA erroneously included Wisconsin in the NO_X SIP Call because EPA failed to explain how Wisconsin contributes to nonattainment in any other State,'' *Michigan*, 213 F.3d at 681 (emphasis in original). The Court noted that the record showed only that emissions from Wisconsin contribute to violations of the standard over Lake Michigan.

Our "zero-out'' modeling of Wisconsin emissions using UAM-V shows that emissions from Wisconsin impact ozone levels in neighboring States, but not during exceedances of the 1-hour NAAQS (*i.e.*, these impacts occur when ozone levels are below the NAAQS). For the OTAG episodes we modeled, the ozone impacts of Wisconsin on 1-hour nonattainment are predicted in the northwestern part of Lake Michigan near the shore line of Wisconsin. In the NO_X SIP Call rulemaking, we concluded that impacts over the lake should be considered as contributions to States bordering the lake (*i.e.*, Michigan, Indiana, and Illinois) because of lake breeze effects (63 FR 57386, October 27, 1998). The Court found that we had not provided adequate support for this determination and vacated the rule's application to Wisconsin for the 1-hour standard. Michigan, 213 F.3d at 681.

We agree that additional modeling would be necessary in order to find that Wisconsin significantly contributes to downwind 1-hour nonattainment in any other State and to include Wisconsin in the NO_X SIP Call at this time. We do not currently have the modeling necessary to take such action, therefore, we are excluding the entire State of Wisconsin from the requirements of the 1-hour basis of the NO_X SIP Call to conform to the Court's decision. In addition, we received only one comment on excluding Wisconsin from the NO_X SIP Call and it supported our proposal to do so.

We are not, however, determining that Wisconsin's emissions do not contribute significantly to nonattainment downwind. We have not completed the additional modeling analysis for the States that are part of the OTAG region but were not included in the final NO_X SIP Call. Although we stayed the 8-hour basis of the NO_X SIP Call Rule on September 18, 2000 (65 FR 56245), we are in the process of evaluating lifting the stay. Today's action to exclude Wisconsin from the 1-hour basis of the NO_X SIP Call does not address whether Wisconsin should remain subject to the 8-hour basis of the NO_X SIP Call. We will address that issue at the time we lift the stay as it applies to Wisconsin.

M. How Are the 8-hour Ozone NAAQS Rules Affected by This Action?

As noted above, the revisions to the NO_X SIP Call in today's action respond to the Court's decision in *Michigan*. The Court's decision and today's action concern issues arising under only the 1-hour ozone NAAQS, and not the 8-hour ozone NAAQS. Accordingly, none of the actions finalized today—the definitions of EGU and non-EGU and the control requirements for IC engines, and implications for the State budgets; the SIP submission dates; compliance dates; the revised emissions budgets for Alabama, Georgia, Michigan, and Missouri; and the exclusion of Wisconsin—have any effect on any requirements of the NO_X SIP Call on States under the 8-hour ozone NAAQS. Because of the litigation concerning the 8-hour ozone NAAQS, we stayed all of the requirements of the NO_X SIP Call under the 8-hour ozone NAAQS, ranging from the SIP submission dates to the control requirements (65 FR 56245, September 18, 2000). Since then, the Supreme Court has held that the CAA authorizes EPA to revise the ozone NAAQS. *Whitman* v. *American Trucking Ass'ns.*, 121 S. Ct. 903 (2001).

At this time, we are evaluating the process for lifting the 8-hour stay. Originally, the NO_X SIP Call requirements under the 1-hour and 8-hour standards were the same. As a result of court actions, some parts of the 1-hour NO_X SIP Call are being modified in this rule.

For the Interstate Air Quality Rule (IAQR), which we proposed on January 30, 2004 (FR 69 4566), we reassessed the 8-hour transport following the approach used in the NO_X SIP Call, but using an updated model and updated inputs that reflect current requirements, including the NO_X SIP Call. The IAQR proposes additional control requirements for 2010 and 2015 to address the transport that remains in later years after the implementation of the NO_X SIP Call. For a more detailed discussion of how the NO_X SIP Call and the IAQR would interact, see the IAQR proposal.

N. What Modifications Are Being Made to Parts 51, 78, and 97?

Today's action makes certain modifications to 40 CFR Part 51, the implementing regulations for the NO_X SIP Call Rule, that were promulgated on October 28, 1998. These modifications, which include clarifications, definitions, and minor changes, are being made in response to the various court decisions on the NO_X SIP Call, (*Michigan* v. *EPA*, 213 F. 3d 663 (DC Cir. 2000), *cert denied*, 121 S. Ct. 1225 (2001)), the NO_X SIP Call Technical Amendments (*Appalachian Power* v. *EPA*, 251 F. 3d 1026 (DC Cir. 2001)), and the Section 126 Rule (*Appalachian Power* v. *EPA*, 249 F. 3d 1042 (DC Cir. 2001)).

In response to the court decision in *Michigan*, the Agency divided the NO_X SIP Call into two phases (Phase I and Phase II), thereby enabling the Agency to proceed with those portions of the NO_X SIP Call that were upheld by the Court. Phase II addresses issues that were either remanded or remanded and vacated by the Court. As a result of the various court challenges and decisions referenced above, most of the applicable dates are no longer correct. States are now complying or have complied with dates either set by the Court or dates triggered by the court decisions. Today's action modifies the applicable provisions to reflect the revised applicable dates. In most instances, today's revisions do not include specific dates but rather specify a timeframe, either during the first or second ozone season, in relation to when the Phase I and Phase II sources are subject to control measures and other applicable requirements. New § 51.121(a)(3) defines "Phase I'' and "Phase II.''

Section 51.121(b)(1)(ii) is modified to specify the new dates for implementation of required control measures under Phase I and Phase II. All subsequent sections are modified to align with these new implementation dates. Section 51.121(b)(2)(ii)(B) is modified to reflect the period during which States may accumulate early reduction credits that may be subsequently utilized for compliance with the NO_X SIP Call requirements. Section 51.121(b)(2)(ii)(C) is also modified to specify the new period during which States may bank emissions credits. Section 51.121(b)(2)(ii)(D) is modified to reflect the new period when banked allowances will not be affected by the limitation on the use of banked emissions reductions credits or emissions allowances or the flow control provisions. Compliance supplement pool credits are considered banked at the start of the second year of the NO_X SIP Call program and are therefore, subject to the flow control provisions.

Section 51.121(b)(2)(ii)(E) is modified to reflect the new period when flow control provisions will be triggered. The compliance date for the initial NO_X SIP Call program was May 1, 2003, and the flow control provisions were to begin in the second year of the program, *i.e.*, 2004. However, in *Michigan*, the Court ruled that May 31, 2004, rather than May 1, 2003, is the compliance date for sources now covered under Phase I. Since then, we have implemented the new flow control dates through notice and comment rulemakings for approval of State NO_X SIP Call SIPs, except for Georgia and Missouri. Flow control issues for Georgia and Missouri will be addressed in the context of reviewing their SIPs, as discussed in section I.1. of this rule.

Section 51.121(c), which specifies the States subject to the NO_X SIP Call with respect to the 1-hour ozone NAAQS, is modified by adding sections

51.121(c)(1) and (c)(2). New § 51.121(c)(1) specifies States that all areas of the State are subject to the NO_X SIP Call, and § 51.121(c)(2) specifies those States that only areas of the State that lie within the fine grid portions are subject to the NO_X SIP Call. Section 51.121(c)(2) also defines the fine grid for purposes of the NO_X SIP Call.

Section 51.121(d) is modified to reflect dates by which all the States subject to the NO_X SIP Call must submit required SIP revisions to EPA for Phase I and Phase II. This revision reflects the Phase I SIP submittal date of October 30, 2000, which was set by the Court in *Michigan*. Phase II SIPs are now due by April 1, 2005.

Section 51.121(e)(2) is renumbered and modified to reflect the revised NO_X budgets for each State. Section 51.121(e)(2)(i) contains the modified table reflecting changes to the State-by-State NO_X budgets. New § 51.121(e)(2)(ii) (A)–(D) specifies counties, which lie within the fine grid, in the States of Alabama, Georgia, Michigan, and Missouri that are subject to the NO_X SIP Call requirements.

Section 51.121(e)(3) is being renumbered as § 51.121(e)(4). A new § 51.121(e)(3)(i) is added to define the portion of the NO_X budget that may be included in a Phase II SIP submission for each State.

In § 51.121(e)(4)(i) the period within which sources may use CSP credits to demonstrate compliance with the NO_X SIP Call requirements is modified. This revision is consistent with the original 2-year window specified in the NO_X SIP Call (63 FR 57428–57430, October 27, 1998). Allowances from the CSP must be used by September 30, 2005 and September 20, 2008, for Phase I and Phase II sources, respectively. Section 51.121(e)(4)(ii) is modified by revising the date after which sources may not use CSP credits. Section 51.121(e)(4)(iii) is modified to show the revised State-by-State CSP amounts. Section 51.121(e)(4)(iv)(A) is modified by revising the period during which sources must implement emissions reductions to receive CSP credits. Section 51.121(e)(4)(iv)(A)(1) is modified by revising the date by which States are to complete issuance of CSP credits to sources covered by the NO_X SIP Call. Section 51.121(e)(4)(iv)(A)(3) is modified by revising the period during which emissions reductions must occur for sources to qualify for CSP credits. Section 51.121(e)(4)(iv)(B) is modified by revising the former control implementation date to reflect the new control implementation dates. Section 51.121(e)(4)(iv)(B)(1) is modified to reflect new dates by which States must initiate the issuance of CSP credits. Section 51.121(e)(4)(iv)(B)(2) is modified by revising the date by which the States are to complete issuance of CSP credits. Sections 51.121(e)(4)(iv)(B)(3)(i) and (ii) are modified to reflect the new control implementation dates.

Section 51.121(e)(4) is renumbered as section 51.121(e)(5).

Sections 51.122 (g)(1) and (2) are modified to reflect the beginning and frequency of annual and triennial emissions reporting by States. A new Table is inserted. Section 51.122 (h)(1) is modified to specify the address for submission of the required reports.

Today's action also finalizes modifications to 40 CFR parts 78 and 97 that were proposed on June 13, 2001. The modifications to part 78 were proposed so that affected sources under the Federal NO_X Budget Trading Program would have the same right of administrative appeal as affected sources under the Acid Rain Program. We received no comments on the revisions to part 78. The proposed revisions to part 97 were made in order to align monitoring and reporting requirements with modification to part 75 made after the promulgation of part 97 and to correct certain grammatical and technical errors. We received two comments, one supporting a proposed revision to part 97 and the other suggesting a change that was addressed in the June 12, 2002 final revisions to part 75 (in § 75.19).

We are finalizing the proposed modifications to parts 78 and 97 as proposed, with only three exceptions of any significance.[60] The final revisions to § 97.61(b) differ from the proposed revisions in that the final revisions use language consistent with language in the analogous provision in § 96.61(b) of the model rule for the NO_X Budget Trading Program under the NO_X SIP Call. In particular, the final revisions refer to "the control period to which the NO_X allowance transfer deadline applies,'' rather than referencing "the control period in the same year as the NO_X allowance transfer deadline.'' We believe that the language in the final revisions to § 97.61(b) is clearer and more accurate than the language in the proposed revisions, as well as being analogous to the language in § 96.61(b).

Further, the final revisions to § 97.70(b)(5) and (6) differ from the proposed revisions in that the final revisions use language consistent with language in the analogous provision in § 75.4(e) of the Acid Rain Program emission monitoring regulations. In particular, the final revisions add, to the language "a new stack or flue,'' a reference to new "add-on NO_X emission controls.'' As a result, § 97.70(b)(5) and (6) contain the same references to new stacks, flues, or add-on NO_X emission controls as § 75.4(e). Similarly, the final revisions to § 97.71(c) differ from the proposed revisions in that the final revisions use language consistent with language in the analogous provision in § 75.20(h)(3) of the Acid Rain Program emission monitoring regulations. In particular, the final revisions [similar to § 75.20(h)(3)] provide that provisional certification status for the low mass emission excepted methodology is tied to receipt of a "complete'' certification application.

[60] In addition, the final revisions correct, without any substantive changes, a few minor, technical errors in the proposed revisions or that were inadvertently left out of the proposed revisions.

III. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;
2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
3. Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

This action, which responds to the court decisions in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000) (NO_X SIP Call); *Appalachian Power* v. *EPA,* 249 F.3d 1032 (DC Cir. 2001) (Section 126 Rule), and *Appalachian Power* v. *EPA,* 251 F.3d 1026 (DC Cir. 2001) (NO_X SIP Call Technical Amendments), is a "significant regulatory action'' under Executive Order 12866 because it raises novel legal or policy issues and is, therefore, subject to review by OMB.

Because this is a "significant regulatory action,'' a Regulatory Impact Analysis (RIA) is required. We are using the original RIAs prepared for the three actions at issue in the cases listed above ["Regulatory Impact Analysis for the NO_X SIP Call, FIP, and Section 126 Petitions'' (Docket OAR–2001–0008)] and ["Regulatory Impact Analysis for the Final Section 126 Rule'' (Docket A–97–43)], which contain cost and benefit analyses and economic impact analyses reflecting requirements of those rules. In addition, for IC engines, we are using an update to some of the information in the final NO_X SIP Call RIA entitled, "NO_X Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NO_X SIP Call States'' (August 11, 2000) and "Stationary Reciprocating Internal Combustion Engines: Updated Information on NO_X Emissions and Control Techniques,'' (September 1, 2000). This analysis indicates that there is less cost incurred per engine than shown in the original RIA which was prepared for the final NO_X SIP Call. These documents are available for public inspection in Docket OAR–2001–0008 which is listed in the **ADDRESSES** section of this preamble. Although the original RIA estimated costs for controls on IC engines of $100 million, we now estimate a cost of less than $33 million due to fewer sources affected, lower cost per ton, and a lower average control level ($1990, ozone season). In addition, we now estimate the costs for controls in Georgia and Missouri to be approximately $136 million. Due to today's action to remove Wisconsin and portions of Alabama, Georgia, Michigan, and Missouri from the 1998 NO_X SIP Call rule, the costs estimated in the 1998 RIA are lowered by about $146 million).

B. Paperwork Reduction Act

Today's action does not add any information collection requirements or increase burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), and therefore is not subject to these requirements.

C. Regulatory Flexibility Act (RFA)

The EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined in the Small Business Administration's (SBA) regulations at 13 CFR 12.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities. This final rule responds to the court decisions in *Michigan* v. *EPA,* 213 F.3d 663, *Appalachian Power* v. *EPA,* 249 F.3d 1032 (DC Cir. 2001), and *Appalachian Power* v. *EPA,* 251 F.3d 1026 (DC Cir. 2001) (decisions on the NO_X SIP Call, Section 126 Rule, and NO_X SIP Call Technical Amendments, respectively). The RIA for the original final NO_X SIP Call included impacts to small entities presuming the application of the control strategies we modeled as surrogates for what the States would actually employ in their NO_X SIPs. We also prepared an analysis of impacts to small entities affected by the Section 126 Rule. This analysis is summarized in the RIA for the final Section 126 Rule and included in the docket for that rule. This action does not impose any requirements on small entities nor will there be impacts on small entities beyond those, if any, required by or resulting from the NO_X SIP Call and the Section 126 Rules.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, 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 rules with "Federal mandates'' that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million or more in any 1 year. A "Federal mandate'' is defined to include a "Federal intergovernmental mandate'' and a "Federal private sector mandate'' [2 U.S.C. 658(6)]. A "Federal intergovernmental mandate,'' in turn, is defined to include a regulation that "would impose an enforceable duty upon State, local, or tribal governments,'' [2 U.S.C. 658(5)(A)(i)], except for, among other things, a duty that is "a condition of Federal assistance'' [2 U.S.C. 658(5)(A)(I)]. A "Federal private sector mandate'' includes a regulation that "would impose an enforceable duty upon the private sector,'' with certain exceptions [2 U.S.C. 658(7)(A)].

The EPA prepared a statement for the final NO_X SIP Call that would be required by UMRA if its statutory provisions applied. Today's action does not create any additional requirements beyond those of the final NO_X SIP Call, therefore, no further UMRA analysis is needed.

An Unfunded Mandates Analysis was prepared for the proposed Section 126 Rule which was published on May 25, 1999. The EPA updated this analysis for the final Section 126 Rule (January 18, 2000). This "Government Entity Analysis for the Final Section 126 Petitions Under the Clean Air Act Amendments Title I,'' is available for public inspection in Docket A–97–43 which is listed in the **ADDRESSES** section of this preamble. This analysis determined that the final Section 126 rulemaking contained no regulatory requirements that might significantly or uniquely affect small governments. Today's action imposes no new additional requirements above those established in the final Section 126 Rule.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled "Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' "Policies that have federalism implications'' is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.'' Under section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. The EPA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This action addressing the NO_X SIP Call and Section 126 Rules does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

In issuing the NO_X SIP Call, EPA acted under section 110(k)(5), which requires the Agency to require a State to correct a deficiency that EPA has found in the SIP. In October 1998, EPA issued its final NO_X SIP Call Rule finding that the SIPs for 22 States and the District of Columbia were substantially inadequate because they did not regulate emissions that significantly contribute to downwind nonattainment in other States. On March 3, 2000, the DC Circuit largely upheld that rule but remanded certain minor issues and vacated and remanded other minor issues to the Agency for further consideration. *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000) (NO_X SIP Call). Today, EPA is finalizing action on these remanded and remanded and vacated portions of the rule. This action also responds to an issue that the court remanded and vacated in the challenge to the NO_X SIP Call Technical Amendments. *Appalachian Power* v. *EPA,* 251 F.3d 1026 (DC Cir. 2001) (NO_X SIP Call Technical Amendments).

With respect to the action concerning the definition of EGU and the level of control for IC engines, action revising the emission budgets for Georgia, Missouri, Alabama, and Michigan, and the SIP submission and source compliance dates, EPA's action does not impose any additional burdens beyond those imposed by the final NO_X SIP Call. Thus, today's action does not alter the relationship established by the final NO_X SIP Call Rule, which remains in place for 19 States (including Alabama and Michigan) and the District of Columbia. Moreover, no aspect of this rule changes the established relationship between the States and EPA under title I of the CAA. Under title I of the CAA, States have the primary responsibility to develop plans to attain and maintain the NAAQS. As found by the court, the States have full discretion under the NO_X SIP Call Rule to choose the control requirements necessary to address the transported emissions identified by EPA in the NO_X SIP Call Rule.

As provided in the final action promulgating the NO_X SIP Call Rule and the Technical Amendments, the NO_X SIP Call Rule will not impose substantial direct compliance costs. While the States will incur some costs to develop the plan, those costs are not expected to be substantial. Moreover, under section 105 of the CAA, the Federal government supports the States' SIP development activities by providing partial funding of State programs for the prevention and control of air pollution. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

Today's rule also responds to the Court's decision in *Appalachian Power* v. *EPA,* 249 F.3d 1032 (DC Cir. 2001) (Section 126 Rule). This action imposes no new requirements that impose compliance burdens beyond those that EPA established under the final Section 126 Rule (January 18, 2000).

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 6, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' "Policies that have tribal implications'' is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian tribes, on the relationship between the Federal government and the Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes.''

This rule does not have Tribal implications. It will not have substantial direct effects on Tribal governments, on the relationship between the Federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified in Executive Order 13175. Today's action does not significantly or uniquely affect the communities of Indian Tribal governments. The EPA stated in the final NO_X SIP Call Rule, the Technical Amendments Rule, and the Section 126 Rule that Executive Order 13084 did not apply because those final rules do not significantly or uniquely affect the communities of Indian Tribal governments or call on States to regulate NO_X sources located on Tribal lands. The same is true of today's action. Thus, Executive Order 13175 does not apply to this rule.

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

Executive Order 13045: "Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have 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.

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it does not concern an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children and it is not economically significant under Executive Order 12866.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This summary of the energy impact analysis report dated October 2, 2001 [Docket No. OAR–2001–0008, Item No. XII–L–06] estimates the energy impacts associated with the Phase II portion of the NO_X SIP Call, in accordance with Executive Order 13211. It covers all large EGUs that do not participate in the Acid Rain Trading Program and large IC engines in the District of Columbia and the 21 States of the NO_X SIP Call region, as well as all NO_X SIP Call sources (cement kilns, utility boilers, industrial boilers, combustion turbines, and IC engines) in the fine grid portions of Georgia and Missouri. This analysis also considered impacts on sources in only the fine grid portions of Michigan and Alabama. We identified applications of control devices appropriate for this analysis that provide high levels of NO_X reduction at relatively low cost, with an average cost of less than $2,000 (1990 dollars) per ozone season ton of NO_X removed, among them: SCR and NSCR, fluid injection (steam or ammonia—termed SNCR), and LEC. Through the analysis, we identified three relevant energy effects that occur during normal operation of these devices: increased energy demands required by certain control devices and equipment, increased energy use due to pressure drop and changes in the stoichiometry of the combustion process, and energy credits from improved combustion. Each of these NO_X controls has at least one of these energy effects as part of their normal operation.

The United States consumed over 22 quads (quadrillion Btus) of natural gas in 1999.[61] With respect to energy sources, the application of LEC technology to natural gas-driven IC engines amounts to a savings of about 4,000 mmBtus per unit, or about 70 billion Btus for all affected IC engines (about 70 million cubic feet of gas). This amounts to about three tenths of one percent of the nation's annual consumption. Consequently, the application of LEC technology leads to a small savings in natural gas use nationwide by affected sources and their firms, but not a large enough savings to affect the price or distribution of gas in the United States.

The additional coal necessary to compensate for the loss of efficiency from SCR and SNCR controls amounts to about 11 mmBtus per affected coal-fired boiler, or 89 mmBtus per year per source. For all affected utility and industrial coal-fired boilers, this translates to slightly more than 70 billion Btus. The United States also consumed over 22 quads of coal in 1999. Therefore, the net increase in coal consumption necessary for affected boilers to compensate for their efficiency loss amounts to about three ten-thousandths of one percent of the nation's annual demand for coal. The change in demand for coal caused by NO_X control efficiency loss will not be of sufficient magnitude to affect coal prices. In addition, the reduction in electricity output in response to the requirements of the Phase II NO_X SIP Call rulemaking is less than one-half of one percent of predicted nationwide output between 2005 and 2010 (to approximate a 2007 projection). Because utilities constantly adjust their output to match demand, and because demand fluctuates more widely than the predicted reduction in electricity output from the Phase II rulemaking, this report indicates there will be no significant effect on production or the factors of production imposed by the NO_X SIP Call for affected boilers.

Therefore, we conclude that the rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For more information on the results of this analysis, please consult the energy impact analysis report in the public docket for this rule.

We received four comments on this administrative requirement as summarized below (XII–D–07, TX Gas Transmission Corp.; XII–D–09, INGAA; XII–D–10, El Paso Corp.; XII–F–12, NiSource, Inc.).

Comment: Executive Order 13211 requires us to analyze the effect of its regulations on the Nation's energy supply, distribution and use. Commenters state that (1) We failed to analyze, or even recognize, its deadline's potential effect on the United States' natural gas transmission system (XII–F–12), (2) the proposal's impractical compliance deadline could compromise much of the Nation's gas transmission and storage system, yet there has been no analysis of this issue, (3) EPA must provide a compliance period that is adequate to avoid these problems, and (4) the Agency must conduct a study that demonstrates (after notice and opportunity for comment) that it has fully considered all of the impacts on energy supply and distribution. (p. 12 of comment XII–D–09 and p. 13 of comment XII–D–10.)

Response: We disagree with the comment that we failed to analyze the effect of this rule on the Nation's energy supply, distribution and use. In accordance with Executive Order 13211, we completed an energy impact analysis of this rule, on October 2, 2001. The analysis indicated minimal effects, less than 0.5 percent nationally, on both energy supply, distribution and demand, including natural gas.

We note that the more prevalent LEC retrofit, which has been in use for almost 20 years, is the screw-in precombustion chamber.[62] This kind of retrofit is both less costly and time-consuming than other kinds of LEC retrofit. For example, Columbia Gas Transmission Corporation, using screw-in precombustion chambers, retrofit two IC engines at its Bedford County, Pennsylvania, facility within 3 days.[63] We have also found that most, if not all, natural gas pipeline stations are equipped with multiple IC engines and that not all engines are operated at the same time. Therefore, we believe that LEC retrofits can be phased-in making it less likely for an entire station to go offline for a LEC retrofit. Thus, because a phased-in approach is feasible, we believe that engine stations can continue operating close to their standard level thereby avoiding service interruptions. We also note that the December 1998 Gas Research Institute report concluded that "installation of the [LEC] retrofit kit is not expected to impact the normal maintenance interval.''[64] The energy impact analysis also indicated that IC engines retrofit with LEC will experience, on average, an energy savings of half a million BTUs per hour per engine, and therefore savings in operating costs.

The comment that the 11-month compliance deadline could compromise the nation's gas transmission and storage system is no longer an issue because we are allowing more than 24 months from SIP submittal date for implementation of controls. Our response to this comment is fully discussed in section II.K.2 of this rule, "What Compliance Date Are We Finalizing for IC Engines and What is the Technical Feasibility of This Date?''

With the improvements in ease of LEC retrofits that include scheduling retrofits during maintenance cycles, the adequate time we believe exists for implementation, and the flexibility granted to States to meet their NO_X budgets, we do not believe the concerns expressed about effects on natural gas transmission from compliance with the Phase II NO_X SIP Call rule are warranted.

I. National Technology Transfer Advancement Act

The National Technology Transfer Advancement Act of 1997 does not apply because today's action does not require the public to perform activities conducive to the use of voluntary consensus standards under that Act in the NO_X SIP Call, and NO_X SIP Call Technical Amendments. Today's final action also does not impose additional requirements over those in the final Section 126 Rule. The EPA's compliance with these statutes and Executive Orders for the underlying rules, the final NO_X SIP Call (63 FR 57477, October 27, 1998), the NO_X SIP Call Technical Amendments (64 FR 26298, May 14, 1999; 65 FR 11222, March 2, 2000), and the final Section 126 Rule (65 FR 2674, January 18, 2000) is discussed in more detail in the citations shown above.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

This action does not involve special consideration of environmental justice related issues as required by Executive

[61] National Energy Foundation Web page: *http://www.nef1.org/ea/eastats.html.*

[62] Stationary Reciprocating Internal Combustion Engines Updated Information on NO_X Emissions and Control Techniques, Revised Final Report, prepared by Ec/R, Inc. for EPA, p. 4–2, September 1, 2000, available on the Internet at *http://www.epa.gov/ttn/naaqs/ozone/rto/fip/data/rfic_engine.pdf.*

[63] Found in reprint of article in "American Gas & Oil Reporter,'' May 1998, available on the Internet at *http://www.dieselsupply.com/dscartic.htm.*

[64] "NO_X Control for Two-Cycle Pipeline Reciprocating Engines,'' p. 4–11, December 1998.

Order 12898 (59 FR 7629, February 16, 1994). For the final NO_X SIP Call and Section 126 Rules, the Agency conducted general analyses 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 requirements of these rules. These findings were presented in the RIA for each of these rules. Today's action does not affect these analyses.

K. 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 June 21, 2004.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Environmental protection, Intergovernmental relations, Ozone, Reporting and recordkeeping requirements.

40 CFR Part 78

Air pollution control, Nitrogen oxides, Ozone, Acid Rain Program, Trading budget, Compliance supplement pool.

40 CFR Part 97

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Reporting and recordkeeping requirements.

Dated: April 1, 2004.

Michael O. Leavitt,

Administrator.

■ For the reasons set out in the preamble, title 40 chapter of the Code of Federal Regulations is amended as follows:

PART 51—[Amended]

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

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

■ 2. Section 51.121 is amended:
■ a. By adding paragraph (a)(3).
■ b. By revising paragraphs (b)(1)(ii), (b)(2)(ii)(B), (b)(2)(ii)(C), (b)(2)(ii)(D), and (b)(2)(ii)(E) introductory text.
■ c. By revising paragraph (c).
■ d. By revising paragraph (d)(1).
■ e. By revising paragraphs (e)(1) and (e)(2).
■ f. By redesignating paragraphs (e)(3) and (e)(4) as (e)(4) and (e)(5).
■ g. By adding a new paragraph (e)(3).
■ h. By revising newly designated paragraphs (e)(4)(i), (e)(4)(ii), (e)(4)(iii), (e)(4)(iv)(A) introductory text, (e)(4)(iv)(A)*(1)*, (e)(4)(iv)(A)*(3)*, (e)(4)(iv)(B) introductory text, (e)(4)(iv)(B)*(1)*, (e)(4)(iv)(B)*(2)*, (e)(4)(iv)(B)*(3)(i)*, (e)(4)(iv)(B)*(3)(ii)*, (e)(4)(iv)(B)*(3)(iii)*.

The revisions and additions read as follows:

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

(a) * * *

(3)(i) For purposes of this section, the term "Phase I SIP Submission'' means those SIP revisions submitted by States on or before October 30, 2000 in compliance with paragraph (b)(1)(ii) of this section. A State's Phase I SIP submission may include portions of the NO_X budget, under paragraph (e)(3) of this section, that a State is required to include in a Phase II SIP submission.

(ii) For purposes of this section, the term "Phase II SIP Submission'' means those SIP revisions that must be submitted by a State in compliance with paragraph (b)(1)(ii) of this section and which includes portions of the NO_X budget under paragraph (e)(3) of this section.

(b) * * *

(1) * * *

(ii) Requires full implementation of all such control measures by no later than May 31, 2004 for the sources covered by a Phase I SIP submission and May 1, 2007 for the sources covered by a Phase II SIP submission.

(2) * * *

(ii) * * *

(B) Emissions reductions occurring prior to the first year in which any sources covered by Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section may be used by a source to demonstrate compliance with the SIP revision for the first and second ozone seasons in which any sources covered by a Phase I or Phase II SIP submission are subject to such control measures, provided the SIPs provisions regarding such use comply with the requirements of paragraph (e)(4) of this section.

(C) Emissions reductions credits or emissions allowances held by a source or other person following the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section 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 first ozone season in which any sources covered by Phase I or Phase II submissions are subject to the control measures under paragraph (b)(1)(i) of this section are not subject to the flow control provisions set forth in paragraph (b)(2)(ii)(E) of this section.

(E) Starting with the second ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section, the SIP shall include provisions to limit the use of banked emissions reductions credits or emissions allowances beyond a predetermined amount as calculated by one of the following approaches:

* * * * *

(c) The following jurisdictions (hereinafter referred to as "States'') are subject to the requirement of this section:

(1) With respect to the 1-hour ozone NAAQS: Connecticut, Delaware, Illinois, Indiana, Kentucky, Maryland, Massachusetts, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and the District of Columbia.

(2) With respect to the 1-hour ozone NAAQS, the portions of Missouri, Michigan, Alabama, and Georgia within the fine grid of the OTAG modeling domain. The fine grid is the area encompassed by a box with the following geographic coordinates: Southwest Corner, 92 degrees West longitude and 32 degrees North latitude; and Northeast Corner, 69.5 degrees West longitude and 44 degrees North latitude.

(d) * * *

(1) The SIP submissions required under paragraph (a) of this section must be submitted to EPA by no later than

October 30, 2000 for Phase I SIP submissions and no later than April 1, 2005 for Phase II SIP submissions.

* * * * *

(e)(1) Except as provided in paragraph (e)(2)(ii) of this section, 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)(i) 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)(i) The State-by-State amounts of the NO_X budget, expressed in tons, are as follows:

State	Final budget
Alabama	119,827
Connecticut	42,850
Delaware	22,862
District of Columbia	6,657
Georgia	150,656
Illinois	271,091
Indiana	230,381
Kentucky	162,519
Maryland	81,947
Massachusetts	84,848
Michigan	190,908
Missouri	61,406
New Jersey	96,876
New York	240,322
North Carolina	165,306
Ohio	249,541
Pennsylvania	257,928
Rhode Island	9,378
South Carolina	123,496
Tennessee	198,286
Virginia	180,521
West Virginia	83,921
Total	$3,031,527

(ii) (A) For purposes of paragraph (e)(2)(i) of this section, in the case of each State listed in paragraphs (e)(2)(ii)(B) through (E) of this section, the NO_X budget is defined as the total amount of NO_X emissions from all sources in the specified counties in that State, as indicated in paragraph (e)(2)(i) of this section with respect to the State, which the State must demonstrate that it will not exceed in the 2007 ozone season pursuant to paragraph (g)(1) of this section.

(B) In the case of Alabama, the counties are: Autauga, Bibb, Blount, Calhoun, Chambers, Cherokee, Chilton, Clay, Cleburne, Colbert, Coosa, Cullman, Dallas, De Kalb, Elmore, Etowah, Fayette, Franklin, Greene, Hale, Jackson, Jefferson, Lamar, Lauderdale, Lawrence, Lee, Limestone, Macon, Madison, Marion, Marshall, Morgan, Perry, Pickens, Randolph, Russell, St. Clair, Shelby, Sumter, Talladega, Tallapoosa, Tuscaloosa, Walker, and Winston.

(C) In the case of Georgia, the counties are: Baldwin, Banks, Barrow, Bartow, Bibb, Bleckley, Bulloch, Burke, Butts, Candler, Carroll, Catoosa, Chattahoochee, Chattooga, Cherokee, Clarke, Clayton, Cobb, Columbia, Coweta, Crawford, Dade, Dawson, De Kalb, Dooly, Douglas, Effingham, Elbert, Emanuel, Evans, Fannin, Fayette, Floyd, Forsyth, Franklin, Fulton, Gilmer, Glascock, Gordon, Greene, Gwinnett, Habersham, Hall, Hancock, Haralson, Harris, Hart, Heard, Henry, Houston, Jackson, Jasper, Jefferson, Jenkins, Johnson, Jones, Lamar, Laurens, Lincoln, Lumpkin, McDuffie, Macon, Madison, Marion, Meriwether, Monroe, Morgan, Murray, Muscogee, Newton, Oconee, Oglethorpe, Paulding, Peach, Pickens, Pike, Polk, Pulaski, Putnam, Rabun, Richmond, Rockdale, Schley, Screven, Spalding, Stephens, Talbot, Taliaferro, Taylor, Towns, Treutlen, Troup, Twiggs, Union, Upson, Walker, Walton, Warren, Washington, White, Whitfield, Wilkes, and Wilkinson.

(D) In the case of Michigan, the counties are: Allegan, Barry, Bay, Berrien, Branch, Calhoun, Cass, Clinton, Eaton, Genesee, Gratiot, Hillsdale, Ingham, Ionia, Isabella, Jackson, Kalamazoo, Kent, Lapeer, Lenawee, Livingston, Macomb, Mecosta, Midland, Monroe, Montcalm, Muskegon, Newaygo, Oakland, Oceana, Ottawa, Saginaw, St. Clair, St. Joseph, Sanilac, Shiawassee, Tuscola, Van Buren, Washtenaw, and Wayne.

(E) In the case of Missouri, the counties are: Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Franklin, Gasconade, Iron, Jefferson, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Genevieve, St. Francois, St. Louis, St. Louis City, Scott, Shannon, Stoddard, Warren, Washington, and Wayne.

(3) The State-by-State amounts of the portion of the NO_X budget provided in paragraph (e)(1) of this section, expressed in tons, that the States may include in a Phase II SIP submission are as follows:

State	Phase II incremental budget
Alabama	4,968
Connecticut	41
Delaware	660
District of Columbia	1
Illinois	7,055
Indiana	4,244
Kentucky	2,556
Maryland	780
Massachusetts	1,023
Michigan	1,033
New Jersey	−994
New York	1,659
North Carolina	6,026
Ohio	2,741
Pennsylvania	10,230
Rhode Island	192
South Carolina	4,260
Tennessee	2,877
Virginia	6,168
West Virginia	1,124
Total	56,644

(4)(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 to demonstrate compliance in the first and second ozone seasons in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(4)(iii) of this section.

(ii) A source may not use credit from the compliance supplement pool to demonstrate compliance after the second ozone season in which any sources are covered by a Phase I or Phase II SIP submission.

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

State	Compliance supplement pool (tons of NO_X)
Alabama	8,962
Connecticut	569
Delaware	168
District of Columbia	0
Georgia	10,728
Illinois	17,688
Indiana	19,915
Kentucky	13,520
Maryland	3,882
Massachusetts	404
Michigan	9,907
Missouri	5,630
New Jersey	1,550
New York	2,764
North Carolina	10,737
Ohio	22,301
Pennsylvania	15,763
Rhode Island	15
South Carolina	5,344
Tennessee	10,565
Virginia	5,504
West Virginia	16,709
Total	182,625

(iv) * * *

(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 the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section.

(*1*) The State shall complete the issuance process by no later than the commencement of the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section.

* * * * *

(*3*) The emissions reductions must be verified by the source as actually having occurred during an ozone season between September 30, 1999 and the commencement of the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section.

* * * * *

(B) The State may issue some or all of the compliance supplement pool to sources that demonstrate a need for an extension of the earliest date on which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section according to the following provisions:

(*1*) The State shall initiate the issuance process by the later date of September 30 before the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section or after the State issues credit according to the procedures in paragraph (e)(4)(iv)(A) of this section.

(*2*) The State shall complete the issuance process by no later than the commencement of the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section.

(*3*) * * *

(*i*) For a source used to generate electricity, compliance with the SIP revision's applicable control measures by the commencement of the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section, 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 the commencement of the first ozone season in which any sources covered by a Phase I or Phase II SIP submission are subject to control measures under paragraph (b)(1)(i) of this section would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(4)(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)(4)(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.

* * * * *

■ 3. Section 51.122 is amended by:
■ a. revising paragraphs (g)(1), and (g)(2),
■ b. removing paragraph (g)(3) and redesignating paragraph (g)(4) as (g)(3),
■ c. revising paragraph (h)(1).

The revisions read as follows:

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

* * * * *

(g) * * *

(1) Data collection is to begin during the ozone season 1 year prior to the State's NO_X SIP Call compliance date.

(2) Reports are to be submitted according to paragraph (b) of this section and the schedule in Table 1. After 2008, trienniel reports are to be submitted every third year and annual reports are to be submitted each year that a trienniel report is not required.

TABLE 1.—SCHEDULE FOR SUBMITTING REPORTS

Data collection year	Type of report required
2002	Trienniel.
2003	Annual.
2004	Annual.
2005	Trienniel.
2006	Annual.
2007	Year 2007 Report.
2008	Trienniel.

* * * * *

(h) * * *

(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. States can obtain information on the current formats at the following Internet address: *http://www.epa.gov/ttn/chief,* by calling the EPA Info CHIEF help desk at (919) 541–1000 or by sending an e-mail to *info.chief@epa.gov.* Because electronic reporting technology continually changes, States are to contact the Emission Factor and Inventory Group (EFIG) for the latest specific formats.

* * * * *

PART 78—APPEAL PROCEDURES FOR ACID RAIN PROGRAM

■ 1. The authority citation for part 78 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq.*

■ 2. Section 78.1 is amended in paragraph (a)(1) by removing the words "parts 72, 73, 74, 75, 76, and 77 of this chapter'' and adding in its place the words "parts 72, 73, 74, 75, 76, or 77 of this chapter or part 97 of this chapter''; and adding a new paragraph (b)(6) to read as follows:

§ 78.1 Purpose and scope.

(b) * * *

(6) Under part 97 of this chapter:

(i) The adjustment of the information in a compliance certification or other submission and the deduction or transfer of NO_X allowances based on the information, as adjusted, under § 97.31 of this chapter;

(ii) The decision on the allocation of NO_X allowances to a NO_X Budget unit under § 97.41(b), (c), (d), or (e) of this chapter;

(iii) The decision on the allocation of NO_X allowances to a NO_X Budget unit from the compliance supplement pool under § 97.43 of this chapter;

(iv) The decision on the deduction of NO_X allowances under § 97.54 of this chapter;

(v) The decision on the transfer of NO_X allowances under § 97.61 of this chapter;

(vi) The decision on a petition for approval of an alternative monitoring system;

(vii) The approval or disapproval of a monitoring system certification or recertification under § 97.71 of this chapter;

(viii) The finalization of control period emissions data, including retroactive adjustment based on audit;

(ix) The approval or disapproval of a petition under § 97.75 of this chapter;

(x) The determination of the sufficiency of the monitoring plan for a NO_X Budget opt-in unit;

(xi) The decision on a request for withdrawal of a NO_X Budget opt-in unit from the NO_X Budget Trading Program under § 97.86 of this chapter;

(xii) The decision on the deduction of NO_X allowances under § 97.87 of this chapter; and

(xiii) The decision on the allocation of NO_X allowances to a NO_X Budget opt-in unit under § 97.88 of this chapter.

* * * * *

§ 78.2 [Amended]

■ 3. Section 78.2 is amended by removing the words "shall apply to this part'' and adding in its place the words "shall apply to appeals of any final decision of the Administrator under parts 72, 73, 74, 75, 76, or 77 of this chapter.''

■ 4. Section 78.3 is amended:

■ a. In paragraph (b)(3)(i) by adding, after the word "petitioner)'', the words "or the NO_X authorized account representative under paragraph (a)(3) of this section (unless the NO_X authorized account representative is the petitioner)'';

■ b. In paragraph (c)(7) by adding, after the words "title IV of the Act'', the words "or part 97 of this chapter, as appropriate'';

■ c. Redesignating paragraphs (d)(2) and (d)(3) as paragraphs (d)(3) and (d)(4) respectively;

■ d. In newly designated paragraph (d)(3) by adding, after the words "Acid Rain Program'' the words "or on an account certificate of representation submitted by a NO_X authorized account representative or an application for a general account submitted by a NO_X authorized account representative under the NO_X Budget Trading Program''; and

■ e. Adding new paragraphs (a)(3) and (d)(2).

The additions and revisions read as follows:

§ 78.3 Petition for administrative review and request for evidentiary hearing.

(a) * * *

(3) The following persons may petition for administrative review of a decision of the Administrator that is made under part 97 of this chapter and that is appealable under § 78.1(a) of this part:

(i) The NO_X authorized account representative for the unit or any NO_X Allowance Tracking System account covered by the decision; or

(ii) Any interested person.

* * * * *

(d) * * *

(2) Any provision or requirement of part 97 of this chapter, including the standard requirements under § 97.6 of this chapter and any emission monitoring or reporting requirements under part 97 of this chapter.

* * * * *

■ 5. Section 78.4 is amended by adding two new sentences after the third sentence in paragraph (a) to read as follows:

§ 78.4 Filings.

(a) * * * Any filings on behalf of owners and operators of a NO_X Budget unit or source shall be signed by the NO_X authorized account representative. Any filings on behalf of persons with an interest in NO_X allowances in a general account shall be signed by the NO_X authorized account representative. * * *

* * * * *

§ 78.12 [Amended]

■ 6. Section 78.12 is amended in paragraph (a)(2) by adding, after the words "Acid Rain permit'' the words "NO_X Budget permit, or other federally enforceable permit.''

PART 97—FEDERAL NOX BUDGET TRADING PROGRAM

■ 1. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7426, and 7601.

■ 2. Section 97.2 is amended by:

■ a. Revising the definition of "Continuous emission monitoring system or CEMS'';

■ b. In the definition of "Fossil fuel fired'' by revising the first occurrence of the word "combination'' in paragraphs (1), (2), and (3)(i) to read "combustion'';

■ c. In the definition of "Most stringent State or Federal NO_X emissions limitation'' by removing the words ", with regard to a NO_X Budget opt-in unit,'';

■ d. In the third sentence of the definition of "NO_X allowance'' by adding the reference "§ 97.40,'' after the word "except'';

■ e. In the definition of "NO_X Budget unit'' by removing the words "Trading Program'';

■ f. In the definition of "owner'' by adding the word "the'' before the final occurrence of the word "NO_X'' in paragraph (4) of the definition; and

■ g. In the definition of "Percent monitor data availability'' by revising the words "§ 94.84(b)'' to read "§ 97.84(b)'', revising the words "3,672 hours per'' to read "the total number of unit operating hours in the'', and by revising the symbol "%'' to read "percent''.

The revisions and additions read as follows:

§ 97.2 Definitions.

* * * * *

Continuous emission monitoring system or *CEMS* means the equipment required under subpart H of this part to sample, analyze, measure, and provide, by means of readings taken at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of nitrogen oxides (NO_X) emissions, stack gas volumetric flow rate or stack gas moisture content (as applicable), in a manner consistent with part 75 of this chapter. The following are the principal types of continuous emission monitoring systems required under subpart H of this part:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS. A flow monitoring system provides a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated DAHS. A NO_X concentration monitoring system provides a permanent, continuous record of NO_X emissions in units of parts per million (ppm);

(3) A nitrogen oxides emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated DAHS. A NO_X concentration monitoring system provides a permanent, continuous record of: NO_X concentration in units of parts per million (ppm), diluent gas concentration in units of percent O_2 or CO_2 (percent O_2 or CO_2), and NO_X emission rate in units of pounds per million British thermal units (lb/mmBtu); and

(4) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter. A moisture monitoring system provides a permanent, continuous record of the stack gas moisture content, in units of percent H_2O (percent H_2O).

* * * * *

§ 97.4 [Amended]

■ 3. Section 97.4 is amended by:

■ a. Revising paragraph (a).

■ b. Amending the first sentence of paragraph (b)(1) by adding, after the words "federally enforceable permit that'', the words "restricts the unit to combusting only natural gas or fuel oil (as defined in § 75.2 of this chapter) during a control period''; and removing "and that'', following "25 tons or less'', and adding in their place ", and'';

■ c. In paragraph (b)(4)(i) by adding, after the words "with the restriction on'', the words "fuel use and''; and

■ d. In paragraph (b)(4)(iv) by adding, after both occurrences of the words "restriction on'', the words "fuel use or'';

■ e. In paragraph (b)(4)(vi)(A) by adding, after the words "restriction on'', the words "fuel use or'';

■ f. In paragraph (b)(4)(vi)(B) by adding, after the words "the restriction on'', the words "fuel use or''.

The revisions and additions read as follows:

§ 97.4 Applicability.

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

(1)(i) For units other than cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit serving during 1995 or 1996 a generator—

(1) With a nameplate capacity greater than 25 MWe and

(2) Producing electricity for sale under a firm contract to the electric grid.

(B) For units commencing operation in 1997 or 1998, a unit serving during 1997 or 1998 a generator—

(1) With a nameplate capacity greater than 25 MWe and

(2) Producing electricity for sale under a firm contract to the electric grid.

(C) For units commencing operation on or after January 1, 1999, a unit serving at any time a generator—

(1) With a nameplate capacity greater than 25 MWe and

(2) Producing electricity for sale.

(ii) For cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit serving during 1995 or 1996 a generator with a nameplate capacity greater than 25 MWe and failing to qualify as an unaffected unit under § 72.6(b)(4) of this chapter for 1995 or 1996 under the Acid Rain Program.

(B) For units commencing operation in 1997 or 1998, a unit serving during 1997 or 1998 a generator with a nameplate capacity grater than 25 MWe and failing to qualify as an unaffected unit under § 72.6(b)(4) of this chapter for 1997 or 1998 under the Acid Rain Program.

(C) For units commencing operation on or after January 1, 1999, a unit serving at any time a generator with a nameplate capacity greater than 25 MWe and failing to qualify as an unaffected unit under § 72.6(b)(4) of this chapter under the Acid Rain Program for any year.

(2)(i) For units other than cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit—

(1) With a maximum design heat input greater than 250 mmBtu/hr and

(2) Not serving during 1995 or 1996 a generator producing electricity for sale under a firm contract to the electric grid.

(B) For units commencing operation in 1997 or 1998, a unit—

(1) With a maximum design heat input greater than 250 mmBtu/hr and

(2) Not serving during 1997 or 1998 a generator producing electricity for sale under a firm contract to the electric grid.

(C) For units commencing on or after January 1, 1999, a unit with a maximum design heat input greater than 250 mmBtu/hr:

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

(2) At any time serving a generator with a nameplate capacity of 25 MWe or less producing electricity for sale and with the potential to use no more than 50 percent of the potential electrical output capacity of the unit.

(ii) For cogeneration units—

(A) For units commencing operation before January 1, 1997, a unit with a maximum design heat input greater than 250 mmBtu/hr and qualifying as an unaffected unit under § 72.6(b)(4) of this chapter under the Acid Rain Program for 1995 and 1996.

(B) For units commencing operation in 1997 or 1998, a unit with a maximum design heat input greater than 250 mmBtu/hr and qualifying as an unaffected unit under § 72.6(b)(4) under the Acid Rain Program for 1997 and 1998.

(C) For units commencing on or after January 1, 1999, a unit with a maximum design heat input greater than 250 mmBtu/hr and qualifying as an unaffected unit under § 72.6(b)(4) of this chapter under the Acid Rain Program for each year.

* * * * *

■ 4. Section 97.5 is amended by:

■ a. In paragraph (c)(6)(i) by removing the word "or''

■ b. In paragraph (c)(6)(ii) by removing the period and replacing it with "; or''; and

■ c. Adding a new paragraph (c)(6)(iii).

The addition reads as follows:

§ 97.5 Retired unit exemption.

* * * * *

(c) * * *

(6) * * *

(iii) The date on which the unit resumes operation, if the unit is not required to submit a NO_X permit application.

* * * * *

§ 97.40 [Amended]

■ 5. Section 97.40 is amended by removing the word "program''.

§ 97.42 [Amended]

■ 6. Section 97.42 is amended by:

■ a. In paragraph (d)(4) by revising the words "a control period'' to read "the control period'';

■ b. In paragraph (e)(1) by adding, before the words 0.15 lb/mmBtu'' and "0.17 lb/mmBtu'' in the formulas, the words "the lesser of'' and by adding, after the words "0.15 lb/mmBtu'' and 0.17 lb/mmBtu'' in the formulas, the words "the unit's most stringent State or Federal emission limitation.''

■ c. In paragraph (e)(2) by revising the words "paragraph (c)(1)'' to read "paragraph (e)(1)''.

§ 97.43 [Amended]

■ 7. Section 97.43 is amended by removing paragraph (c)(8).

§ 97.51 [Amended]

■ 8. Section 97.51 is amended by revising paragraph (b)(1)(i)(D) by adding, after the words "with respect to'', the word "NO_X''.

■ 9. Section 97.54 is amended in paragraph (f) introductory text by removing the colon after the words "as follows'' and by adding a period in its place and by adding a new sentence to the end of the paragraph to read as follows:

§ 97.54 Compliance.

* * * * *

(f) * * * For each State NO_X Budget Trading Program that is established, and approved and administered by the Administrator pursuant to § 51.121 of this chapter, the terms "compliance account'' or "compliance accounts'', "overdraft account'' or "overdraft accounts'', "general account'' or "general accounts'', "States'', and "trading program budgets under § 97.40'' in paragraphs (f)(1) through (f)(3) of this section shall be read to include respectively: A compliance account or compliance accounts established under such State NO_X Budget Trading Program; an overdraft account or overdraft accounts established under such State NO_X Budget Trading Program; a general account or general accounts established under such State NO_X Budget Trading Program; the State or portion of a State covered by such State NO_X Budget Trading Program; and the trading program budget of the State or portion of a State covered by such State NO_X Budget Trading Program.

* * * * *

§ 97.61 [Amended]

■ 10. Section 97.61 is amended in paragraph (b) by revising the words "in a prior year or the same year as the NOX allowance transfer deadline'' to read "prior to or the same as the control period to which the NO_X allowance transfer deadline applies'' and by revising the words "the control period in the same year as the NO_X allowance transfer deadline'' to read "the control period in the fourth year after the control period to which the NO_X allowance transfer deadline applies.''

■ 11. Section 97.70 is amended by:

■ a. In paragraph (a)(1) by removing the words "§§ 75.72 and §§ 75.76''and adding in its place the words "§§ 75.71 and 75.72'';

■ b. Revising paragraph (b)(3);

■ c. Revising paragraph (b)(4);

■ d. Removing paragraphs (b)(5) and (b)(6);

■ e. Redesignating paragraphs (b)(7), (b)(8) and (b)(9) as paragraphs (b)(5), (b)(6), and (b)(7), respectively;

■ f. Revising newly redesignated paragraphs (b)(5) and (b)(6); and

■ g. Revising paragraph (c).

The revisions read as follows:

§ 97.70 General requirements.

* * * * *

(b) * * *

(3) For the owner or operator of a NO_X Budget unit under § 97.4(a) that commences operation on or after January 1, 2003 and that reports on an annual basis under § 97.74(d) by the following dates:

(i) The earlier of 90 unit operating days after the date on which the unit commences commercial operation or 180 calendar days after the date on which the unit commences commercial operation; or

(ii) May 1, 2003, if the compliance date under paragraph (b)(3)(i) of this section is before May 1, 2003.

(4) For the owner or operator of a NO_X Budget unit under § 97.4(a) that commences operation on or after January 1, 2003 and that reports on a control period basis under § 97.74(d)(2)(ii), by the following dates:

(i) The earlier of 90 unit operating days or 180 calendar days after the date on which the unit commences commercial operation, if this compliance date is during a control period; or

(ii) May 1 immediately following the compliance date under paragraph (b)(4)(i) of this section, if such compliance date is not during a control period.

(5) For the owner or operator of a NO_X Budget unit that has a new stack or flue or add-on NO_X emission controls for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section or under subpart I of this part and that reports on an annual basis under § 97.74(d), by the earlier of 90 unit operating days or 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emission controls.

(6) For the owner or operator of a NO_X Budget unit that has a new stack or flue or add-on NO_X emission controls for which construction is completed after the applicable deadline under paragraph (b)(1), (b)(2), (b)(3), or (b)(4) of this section or under subpart I of this part and that reports on a control period basis under § 97.74(d)(2)(ii), by the following dates:

(i) The earlier of 90 unit operating days or 180 calendar days after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emission controls, if this compliance date is during a control period; or

(ii) May 1 immediately following the compliance date under paragraph (b)(6)(i) of this section, if such compliance date is not during a control period.

* * * * *

(c) *Commencement of data reporting.* (1) The owner or operator of NO_X Budget units under paragraph (b)(1) or (b)(2) of this section shall determine, record and report NO_X mass emissions, heat input rate, and any other values required to determine NO_X mass emissions (*e.g.,* NO_X emission rate and heat input rate, or NO_X concentration and stack flow rate) in accordance with § 75.70(g) of this chapter, beginning on the first hour of the applicable compliance deadline in paragraph (b)(1) or (b)(2) of this section.

(2) The owner or operator of a NO_X Budget unit under paragraph (b)(3) or (b)(4) of this section shall determine, record and report NO_X mass emissions, heat input rate, and any other values required to determine NO_X mass emissions (*e.g.,* NO_X emission rate and heat input rate, or NO_X concentration and stack flow rate) and electric and thermal output in accordance with § 75.70(g) of this chapter, beginning on:

(i) The date and hour on which the unit commences operation, if the date and hour on which the unit commences operation is during a control period; or

(ii) The first hour on May 1 of the first control period after the date and hour on which the unit commences operation, if the date and hour on which the unit commences operation is not during a control period.

(3) Notwithstanding paragraphs (c)(2)(i) and (c)(2)(ii) of this section, the owner or operator may begin reporting NO_X mass emission data and heat input data before the date and hour under paragraph (c)(2)(i) or (c)(2)(ii) of this section if the unit reports on an annual basis and if the required monitoring systems are certified before the applicable date and hour under paragraph (c)(1) or (c)(2) of this section.

* * * * *

■ 12. Section 97.71 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. In paragraphs (b)(1), (b)(2), and (b)(3)(ii) by adding the word "emission'' before the words "monitoring system'' in each occurrence in paragraph (b)(1), in both occurrences in the first sentence of paragraph (b)(2), and in the one occurrence in paragraph (b)(3)(ii); and by revising the word "a'' to read "an'' after the word "installs'' in the second sentence of paragraph (b)(1);

■ c. In paragraphs (b)(3)(iii) and (b)(3)(iv)(C) by removing each occurrence of the words "or component thereof''; and

■ d. Revising the second sentence of paragraph (c), adding two new sentences to the end of paragraph (c), and removing paragraphs (c)(i) through (iii).

The revisions and additions read as follows:

§ 97.71 Initial certification and recertification procedures.

(a) The owner or operator of a NO_X Budget unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of part 75 of this chapter for NO_X-diluent CEMS, flow monitors, NO_X concentration CEMS, or excepted monitoring systems under appendix E of part 75 of this chapter for NO_X, under appendix D for heat input, or under § 75.19 for NO_X and heat input, except that:

* * * * *

(c) * * * The owner or operator of such a unit shall also meet the applicable certification and recertification procedures of paragraph (b) of this section, except that the excepted methodology shall be deemed provisionally certified for use under the NO_X Budget Trading Program as of the date on which a complete certification application is received by the

Administrator. The methodology shall be considered to be certified either upon receipt of a written notice of approval from the Administrator or, if such notice is not provided, at the end of the Administrator's 120 day review period. However, a provisionally certified or certified low mass emissions excepted methodology shall not be used to report data under the NO_X Budget Trading Program prior to the applicable commencement date specified in § 75.19(a)(1)(ii) of this chapter.

* * * * *

■ 13. Section 97.72 is amended by:

■ a. In paragraph (a) by adding the word "emission'' before the words "monitoring system'' and the words "subpart H,'' before "appendix D''; and

■ b. In paragraph (b) by revising the words "a monitoring system'' in the first sentence to read "an emission monitoring system'', by removing each occurrence of the words "or component'' in the paragraph, and by adding a sentence to the end of the paragraph.

The revisions read as follows:

§ 97.72 Out of control periods.

* * * * *

(b) * * * The owner or operator shall follow the initial certification or recertification procedures in § 97.71 for each disapproved system.

■ 14. Section 97.74 is amended by revising paragraphs (a)(1), (d)(1), and (d)(2)(ii) to read as follows:

§ 97.74 Recordkeeping and reporting.

(a) * * *

(1) The NO_X authorized account representative shall comply with all recordkeeping and reporting requirements in this section, with the recordkeeping and reporting requirements under § 75.73 of this chapter, and with the requirements of § 97.10(e)(1).

* * * * *

(d) * * *

(1) If a unit is subject to an Acid Rain emission limitation or if the owner or operator of the NO_X budget unit chooses to meet the annual reporting requirements of this subpart H, the NO_X authorized account representative shall submit a quarterly report for each calendar quarter beginning with:

(i) For a unit for which the owner or operator intends to apply or applies for the early reduction credits under § 97.43, the calendar quarter that covers May 1, 2000 through June 30, 2000. The NO_X mass emission data shall be recorded and reported from the first hour on May 1, 2000; or

(ii) For a unit that commences operation before January 1, 2003 and that is not subject to paragraph (d)(1)(i) of this section, the calendar quarter covering May 1, 2003 through June 30, 2003. The NO_X mass emission data shall be recorded and reported from the first hour on May 1, 2003; or

(iii) For a unit that commences operation on or after January 1, 2003:

(A) The calendar quarter in which the unit commences operation, if unit operation commences during a control period. The NO_X mass emission data shall be recorded and reported from the date and hour when the unit commences operation; or

(B) The calendar quarter which includes May 1 through June 30 of the first control period following the date on which the unit commences operation, if the unit does not commence operation during a control period. The NO_X mass emission data shall be recorded and reported from the first hour on May 1 of that control period; or

(iv) A calendar quarter before the quarter specified in paragraph (d)(1)(i), (d)(1)(ii), or (d)(1)(iii)(B) of this section, if the owner or operator elects to begin reporting early under § 97.70(c)(3).

(2) * * *

(ii) Submit quarterly reports, documenting NO_X mass emissions from the unit, only for the period from May 1 through September 30 of each year and including the data described in § 75.74(c)(6) of this chapter. The NO_X authorized account representative shall submit such quarterly reports, beginning with:

(A) For a unit for which the owner or operator intends to apply or applies for the early reduction credits under § 97.43, the calendar quarter that covers May 1, 2000 through June 30, 2000. The NO_X mass emission data shall be recorded and reported from the first hour on May 1, 2000; or

(B) For a unit that commences operation before January 1, 2003 and that is not subject to paragraph (d)(2)(ii)(A) of this section, the calendar quarter covering May 1, 2003 through June 30, 2003. The NO_X mass emission data shall be recorded and reported from the first hour on May 1, 2003; or

(C) For a unit that commences operation on or after January 1, 2003 and during a control period, the calendar quarter in which the unit commences operation. The NO_X mass emission data shall be recorded and reported from the date and hour when the unit commences operation; or

(D) For a unit that commences operation on or after January 1, 2003 and not during a control period, the calendar quarter which includes May 1 through June 30 of the first control period following the date on which the unit commences operation. The NO_X mass emission data shall be recorded and reported from the first hour on May 1 of that control period.

* * * * *

§ 97.87 [Amended]

■ 15. Section 97.87 is amended in the second sentence of paragraph (b)(1)(iii)(A) by adding the word "be'' after the words "shall not''.

■ 16. Subpart J consisting of § 97.90 is added to part 97 to read as follows:

Subpart J—Appeal Procedures

§ 97.90 Appeal procedures.

The appeal procedures for the NO_X Budget Trading Program are set forth in part 78 of this chapter.

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