ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 96, and 97

[FRL–7147–6]

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: Proposed rule.

SUMMARY: In today's action, we are proposing to amend two related final rules we issued under sections 110 and 126 of the Clean Air Act (CAA) related to interstate transport of nitrogen oxides (NO_X), one of the main precursors to ground-level ozone. We are responding to the March 3, 2000 decision of the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in which the Court largely upheld the NO_X State Implementation Plan Call (NO_X SIP Call), but remanded four narrow issues to us for further rulemaking action; the related decision by the D.C. 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; and the decision by the D.C. 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 D.C. Circuit on August 24, 2001, concerning the Section 126 Rule, in which the Court remanded an issue.

In the final NO_X SIP Call, we found that emissions of NO_X from 22 States and the District of Columbia (23 States) significantly contribute to downwind areas' nonattainment of the 1-hour ozone national ambient air quality standards (NAAQS). We established statewide NO_X emissions budgets for the affected States. In rulemakings providing technical amendments to the NO_X SIP Call budgets, we revised those budgets. Today's action addresses the issues remanded by the Court in the two cases involving challenges to both the NO_X SIP Call and the rulemakings providing technical amendments for notice-and-comment rulemaking and proposes related amendments.

In today's action, we are also responding to the D.C. Circuit's decisions in a third case concerning a related rulemaking, the Section 126 Rule, in which the Court remanded an issue and vacated an issue. This action addresses the vacated issue.

DATES: Comments must be postmarked, faxed, or e-mailed by April 15, 2002. A public hearing, if requested, will be held in Washington, DC, on March 15, 2002, beginning at 9:00 am.

ADDRESSES: Comments (in duplicate if possible) may be submitted to the Office of Air and Radiation Docket and Information Center (6102), Attention: Docket No. A–96–56, U.S. Environmental Protection Agency,401 M Street, SW, Washington, DC 20460, telephone (202) 260–7548, fax (202) 260–4400, and e-mail *A-and-R-docket@epa.gov.* We encourage electronic submissions of comments and data following the instructions under **SUPPLEMENTARY INFORMATION** of this document. No confidential business information (CBI) should be submitted through e-mail.

The public hearing, if requested, will be held at Crystal Mall 2 (Room 1110; the ''fishbowl''), Crystal City, 1921 Jefferson Davis Hwy, Arlington, VA 22202.

Documents relevant to this action are available for inspection at the U.S. Environmental Protection Agency, 401 M Street, SW, Waterside Mall, Room M–1500, Washington, DC 20460, between 8 a.m. and 5:30 p.m., Monday through Friday, excluding legal holidays. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: General questions concerning today's action should be addressed to 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 at *king.jan@epa.gov.* Technical questions concerning EGUs in today's document 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 internal combustion 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 Howard J. Hoffman, Office of General Counsel, (2344A), 1200 Pennsylvania Ave., NW, Washington, DC 20460, telephone (202) 564–5582, e-mail *hoffman.howard@epa.gov.*

SUPPLEMENTARY INFORMATION: Today's action addresses the issues remanded or vacated for notice-and-comment rulemaking by the D.C. Circuit in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. 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 (D.C. 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 (D.C. Cir. 2001) and *Appalachian Power* v. *EPA,* No.99–1200, Order (D.C. Cir., August 24, 2001), which concerned the section 126 rulemaking (the ''Section 126 case'').

In this action, we are proposing to:

(1) Retain the definition of EGUs as it relates to cogeneration units in the NO_X SIP Call and in the Section 126 Rule, and retain the definition of EGUs as it relates to cogeneration units in the NO_X SIP Call with only minor revisions to make the definition consistent with the Section 126 Rule.

(2) Revise the control levels for stationary internal combustion engines that were assumed in calculating NO_X SIP call budgets for each State,

(3) Exclude portions of Georgia, Missouri, Alabama and Michigan from the NO_X SIP Call (the court ruling focused on Georgia and Missouri, but the same issue is relevant to Alabama and Michigan),

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

(5) Set a range of dates for 19 States and the District of Columbia to submit State implementation plans to achieve the emissions reductions required by this second phase of the NO_X SIP Call, and for Georgia and Missouri to submit SIPs meeting the full NO_X SIP Call: 6 months through 1 year from final promulgation of this rulemaking but no later than April 1, 2003,

(6) Set a compliance date of May 31, 2004, for all sources except those in Georgia and Missouri; and sources in those two States would have a May 1, 2005 compliance date,

(7) Exclude Wisconsin from NO_X SIP Call requirements.

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 preexisting respiratory disease such as asthma), increased inflammation of the lungs, and possible long-term damage to the lungs.

Public Hearing

A public hearing, if requested, will be held on March 15, 2002 beginning at 9:00 am. The hearing will be held at Crystal Mall 2 (Room 1110, the ''fishbowl''), Crystal City, 1921 Jefferson Davis Hwy, Arlington, VA 22202. The metro stop is Crystal City, which is located about 1 ½ blocks from Crystal Mall 2. If you wish to request a hearing and present oral testimony or attend the hearing, you should notify, on or before March 7, 2002, Ms. JoAnn Allman, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, C539–02, Research Triangle Park, NC 27711, telephone (919) 541–1815, e-mail *allman.joann@epa.gov.* Oral testimony will be limited to 5 minutes each. The hearing will be strictly limited to the subject matter of the proposal, the scope of which is discussed below. Any member of the public may file a written statement by the close of the comment period. Written statements (duplicate copies preferred) should be submitted to Docket No. A–96–56 and, to the extent they concern the Section 126 Rule, Docket No. A–97–43, at the address listed above for submitting comments. The hearing schedule, including lists of speakers, will be posted on EPA's webpage at *http://www.epa.gov/ttn/rto/whatsnew.html.* A verbatim transcript of the hearing and written statements will be made available for copying during normal working hours at the Office of Air and Radiation Docket and Information Center at the above address listed for inspection of documents.

If no requests for a public hearing are received by close of business March 7, 2002, the hearing will be cancelled. The cancellation will be announced on the webpage at the address shown above.

Electronic Availability

Electronic comments are encouraged and can be sent directly to EPA at: *A-and-R-Docket@epa.gov.* Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data will also be accepted on disks in WordPerfect in 8.0 file format or ASCII file format. All comments and data in electronic form must be identified by the docket number A–96–56 and, to the extent they concern the Section 126 Rule, docket number A–97–43. Electronic comments on this proposed rule may be filed online at many Federal Depository Libraries.

Availability of Related Information

The official records for the NO SIP Call rulemaking (including the Technical Amendments) and for the Section 126 Rule, as well as the public versions of the records, have been established under docket numbers A–96–56 and A–97–43, respectively (including comments and data submitted electronically as described below). We have added new sections to those dockets for purposes of today's proposed rulemaking. The public version of these records, including printed, paper versions of electronic comments, which does not include any information claimed as CBI, are available for inspection from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays. The rulemaking records are located at the address in **ADDRESSES** at the beginning of this document. In addition, the **Federal Register** rulemakings and associated documents are located at *http://www.epa.gov/ttn/rto/.*

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 23 States emit NO_X in amounts that significantly contribute to nonattainment of the 1-hour ozone 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 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 23 States emit NO_X in amounts that significantly contribute to nonattainment of the 8-hour ozone NAAQS. However, we have indefinitely stayed the NO_X SIP Call as it applies for the purposes of the 8-hour NAAQS (65 FR 56245, September 18, 2000).

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

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

On May 14, 1999, the D.C. 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 (D.C. 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 D.C. Circuit granted in part and denied in part our rehearing request. *American Trucking Ass'n* v. *EPA,* 194 F.3d 4 (D.C. 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 D.C. 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 D.C. Circuit to consider challenges to the revised ozone NAAQS on other grounds.

2. What Effect Did This 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 D.C. 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 D.C. Circuit issued a stay of the SIP submission deadline pending further order of the Court. *Michigan* v. *EPA*, 213 F.3d 663 (D.C. 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 D.C. 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 geographic and procedural issues. *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000). The Court's decision in *Michigan* v. *EPA*, 213 F.3d 663 (D.C. 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 reduction 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) CAA § 110(a)(2)(D)(i)(I) as construed by us 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 SIP Call; and

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

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 sell electricity to the grid in amounts of either one-third or less of their potential electrical output capacity or 25 megawatts or less per year (small cogenerators); and

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

The Court remanded the last two matters for further rulemaking.

5. How Did the Court Respond to EPA's 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 SIP Call and provided that States could submit only those portions of the 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 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 meets the NO_X SIP Call, these 19 States and the District of Columbia may choose to submit SIPs that cover all of the NO_X SIP Call requirements except for a small part of the EGU portion and large internal combustion engine portion of the budget. We refer to these partial plans that address the portion of the rule unaffected by the Court's remand as the ''Phase I'' SIPs.[2] Because the 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?

On August 30, 2000, the D.C. 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. This action was in response to a motion filed by the industry/labor petitioners.

C. What Was 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)). While the Court has changed the NO_X SIP Call compliance deadline to May 31, 2004, we 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). Thus, the automatic withdrawal provision in the Section 126 Rule does not address any other circumstances. Additional issues regarding the interaction of the Section 126 Rule and SIPs under the NO_X SIP Call may be addressed through future rulemaking.[6]

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

On May 15, 2001, a panel of the D.C. 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 to us 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 cogenerators (cogeneration units that sell electricity to the grid in amounts of either one-third or less of their potential electrical output capacity or 25 megawatts or less per year). Although in the *Michigan* decision (concerning the NO_X SIP Call rulemaking), the D.C. 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 cogenerators as EGUs. In an order dated on August 24, 2001, the D.C. Circuit issued an order in the *Appalachian Power—Section 126 Case*, remanding the Section 126 Rule with regard to the classification of any cogenerators as EGUs and tolling (suspending) the date for EGUs to implement controls pending EPA's 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 settled these cases with several of those sources

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

[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 proposing for the NO_X SIP Call in today's action.

[5] As discussed in the next section, on August 24, 2001, the D.C. Circuit suspended the compliance date for EGUs while we resolve a remanded issue related to EGU growth factors.

[6] A memo dated January 16, 2002 from John Seitz, Director, Office of Air Quality Planning and Standards to the EPA Regional Air Division Directors, indicated our intent to reset the compliance date for EGUs and non-EGUs to May 31, 2004, subject to our response to the growth factor remand.

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 D.C. Circuit Decision on the Technical Amendments?

On June 8, 2001, the D.C. Circuit issued its opinion in a case involving the Technical Amendments. *Appalachian Power* v. *EPA*, 251 F.3d 1026 (D.C. 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 cogenerators as EGUs. In addition, in the *Appalachian 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 D.C. Circuit Remands/Vacaturs?

In summary, the D.C. 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 internal combustion engines;

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

(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 cogenerators as EGUs. *Michigan, Appalachian Power-Section 126, Appalachian Power-Technical Amendments;* and

(9) Remanded the classification of any cogenerators 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 follows:

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 cogenerators or reductions from internal combustion 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. A challenge to those findings has been filed in the D.C. Circuit.

Today's action sets forth our proposal for the second phase or Phase II of the NO_X SIP Call by addressing the classification of cogenerators as EGUs, and adjusting the budgets accordingly; the control level for large internal combustion engines; the date by which States must submit a Phase II budget, and Georgia and Missouri must submit SIPs to meet the full NO_X SIP Call budget; the compliance dates for States to meet their Phase II budgets, and for Georgia and Missouri to meet the full NO_X SIP Call budget; and the emissions budgets for Georgia and Missouri, which are proposed to be based on only the fine-grid portion of these States. In addition, we propose to modify the budgets for Alabama and Michigan based on inclusion of only the fine grid portion of those States. Further, we are proposing to exclude Wisconsin from the NO_X SIP Call.

Any additional emissions reductions required as a result of a final rulemaking on this proposal will be 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 SIP Call. The due date for the SIPs meeting the resulting State emissions budgets (''Phase II'' SIPs) and partial State budgets for Georgia and Missouri is discussed below in sections II.J and II.K. The proposed changes to the State's emissions budgets are discussed in section II.E.

As noted above, today's action proposes to continue the classification of cogenerators as EGUs, and presents support for that classification.

In addition, in today's action, we request that cogenerators that would be subject to classification as EGUs in the NO_X SIP Call and the Section 126 Rule identify themselves as cogenerators and, if applicable, small generators, so that EPA and the States will be able to clarify that portion of their NO_X inventory.

Today's action also includes technical housekeeping by making minor revisions to the NO_X SIP Call definition of EGUs and non-EGUs to make those definitions consistent with the definitions of EGUs and non-EGUs in the Section 126 Rule. Today's proposal retains those definitions in the Section 126 Rule.

Today's proposal does not address the EGU growth remand. We intend to act on that issue separately. If any additional revisions to budgets are necessary, they will be addressed in that action. By notice dated August 3, 2001, we published our preliminary response to the remand in which we indicated that we believed our method for estimating growth in emissions from EGUs was reasonable, we notified the public that we were examining additional data, which we put in the docket, and invited comment on that data (66 FR 40609).

Today's proposal does not address NO_X SIP Call issues related to the 8-hour NAAQS, and we have no plans in the immediate future to announce a specific process for doing so. We have stayed the findings in the NO_X SIP Call based on the 8-hour NAAQS, and are continuing to conduct rulemaking concerning the 8-hour NAAQS.

II. What Is the Scope of This Proposal?

In this action, we are soliciting comment on only the specific changes the Agency is proposing in response to the Court's rulings on the NO_X SIP Call, Section 126, and Technical Amendments rulemakings. We are not reopening the remainder of those three rulemakings for public comment and reconsideration. Specifically, we are soliciting comment on the following:

(1) Certain aspects of the definitions of EGU and non-EGU. We are not proposing to change the manner in which the budgets are calculated for EGUs and non-EGU boilers and turbines under the final NO_X SIP Call, the Technical Amendments, and the Section 126 Rules. We also are not proposing to change the definitions of EGU and non-EGU used in the Section 126 Rules (*e.g.,* in the allocation methodology. We are addressing the issues concerning the definition of EGU as applied to certain cogeneration units by proposing 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.

As part of our treatment of the cogenerator issues, we are increasing the required level of emissions reductions, and thus reducing the budgets, to require reductions from a set of units—termed the non-acid rain units—that we excluded as part of Phase I on grounds that they include small cogenerators.

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 to us their SIP controls at the level that was undisturbed by the Court's ruling. Accordingly, we determined that the SIPs required to be submitted on the schedule established by the Court (October 30, 2000), which we have termed the Phase I SIPs, should reflect all reductions required under the NO_X SIP Call rulemaking except those reductions attributable to parts of the rule that the Court remanded or vacated, including small cogenerators. However, at the time we adopted this position, we were uncertain as to which units constituted small cogenerators, and the total emissions attributable to small cogenerators.

Even so, we were aware that although most of the EGUs that were subject to the NO_X SIP Call were also controlled under the Acid Rain Program, none of the small cogenerators were controlled under the Acid Rain Program. (Units controlled under the Acid Rain Program may be termed ''acid rain units,'' and those not so controlled may be termed ''non-acid rain units.'') 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. As a result, the Phase I SIPs may provide for fewer required reductions and higher budgets than would have been required if EPA had been able to determine which of the non-acid rain units should have been categorized as small cogenerators.

In today's action, we are proposing to continue the classification of certain cogenerators, including small cogenerators, 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. This approach will have the effect of increasing the SIPs' required level of reductions and decreasing the budgets.

In the final rule, we will indicate the sources we believe should be classified as small cogenerators. It is conceivable that this process of identifying sources will lead us to conclude that some of the non-acid rain units should not be included as EGUs and, therefore, that further adjustments to the budgets of particular States may be necessary. In this case, we will make those further adjustments in the final rule. Because we anticipate that only a small number of sources currently meet the definition of small cogenerators, we expect few, if any, revisions to the budgets resulting from today's proposal, and if any revisions do result, we anticipate that they will be very small and will not affect most States.

We are proposing minor, 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 proposed changes to the EGU definition result in corresponding proposed 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 propose any specific revisions to the budgets established under the final NO_X SIP Call and the Technical Amendments.

(2) The control level assumed for large stationary internal combustion engines in the NO_X SIP Call. We are proposing a range of possible control levels (82 to 91 percent) to the internal combustion engine portion of the budget.

(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) A range of SIP submission dates for the 19 States and the District of Columbia to address the Phase II portion of the budget, and for Georgia and Missouri to submit full SIPs meeting the NO_X SIP Call: 6 months through 1 year from final promulgation of this rulemaking, but no later than April 1, 2003.

(6) The compliance date of May 31, 2004 under the NO_X SIP Call for all sources except those in Georgia and Missouri, and the compliance date of May 1, 2005 for sources in Georgia and Missouri.

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

A. How Do We Treat Cogenerators and Non-Acid Rain 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 and large non-EGUs 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 D.C. 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 rulemaking 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 with annual electricity sales of one-third or less of the units' potential electrical output capacity, or 25 megawatts (MWe) or less. (A cogeneration unit may be owned by a utility or a non-utility and is a unit that uses the same energy to produce both thermal energy (heat or steam) that is used for industrial, commercial, or heating or cooling purposes; and electricity.) *Michigan* v. *EPA,* 213 F.3d at 691–92. According to the Court, ''two months after the 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 criteria for the exclusion and treating as EGUs those cogeneration units not meeting the exclusion 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 the criteria for excluding cogeneration units from treatment as utility units. According to the petitioner, the exclusion criteria had been established under the regulations implementing new source performance standards 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 exclusion 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 D.C. Circuit, after considering the merits of the issue, vacated and remanded our classification of small cogenerators as EGUs. The Court held that we had failed to justify this classification and base it on adequate record support comparing the NO_X reduction costs of cogenerators to those of other EGUs or demonstrating that there is no relevant physical or technological difference between small cogenerators and utilities. In the Section 126 decision, the Court also remanded our classification of any cogenerators as EGUs.

We discuss below the historical definition of utility unit, the definition of EGU in the NO_X SIP Call and the Section 126 rulemaking, today's proposed rule addressing certain aspects of the EGU definition, and the rationale for the proposed rule. As discussed below, in prior regulatory programs, we have sought to distinguish between utilities (regulated monopolies in the business of producing and selling electricity) and non-utilities. In making this distinction, we applied the ''one third potential electrical output capacity/25 MWe sales criteria.'' These criteria defined a non-utility unit as a unit producing electricity for annual sales in an amount equal to the lesser of: (i) one-third or less of a unit's potential electrical output capacity; or (ii) 25 MWe or less. Note that the criteria did not always apply only to cogeneration units and did not uniformly result in ''less'' regulation for sources meeting the criteria. With the development of competitive markets for electricity generation and sale, we believe that these criteria no longer distinguish between units in the business of producing and selling electricity (*i.e.,* EGUs) and non-EGUs. In addition, there are no relevant differences between the way cogenerating units and non-cogenerating units are built and operated that justify continuing to use these criteria or that affect the general ability of cogenerating units to control NO_X. We are today proposing to retain the basic definition of EGU in the NO_X SIP Call and the Section 126 Rule and to continue to apply it to cogenerators.

1. What Is the Historical Definition of Utility Unit?

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 new source performance standards 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 new source performance standards. 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'' which, 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). Some of the requirements (e.g., the emission limits for particulate matter) in subpart D or Db were less stringent than those in subpart Da. These criteria applied to all steam generating units, not just cogeneration facilities.

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. We believed that a unit involved in electricity sales small enough to be at or below the levels in the sales criteria was owned by a company whose business was other than electric generation and transmission and/or distribution and so was in the industrial, not the utility, sector. We stated that, ''[s]ince most industrial cogeneration units are expected to be less than 25 MWe electrical output capacity, few, if any, new industrial cogeneration units will be covered by these [subpart Da] standards. The standards do cover large electric utility cogeneration facilities because such units are fundamentally electric utility steam generating units.'' *Id.*

Our approach in subpart Da reflected the fact that, since before the 1970's and into the 1980's, private or public entities in the business of electric generation and transmission and/or distribution (*i.e.,* utilities) produced almost all of the electricity generated or sold in the U.S. In addition, utilities were regulated monopolies with designated service areas. In contrast, non-utilities sold relatively small amounts of electricity, played an insignificant role in the business of electric generation and sales, and were not regulated monopolies. *See The Changing Structure of the Electric Power Industry: An Update,* Energy Information Administration, December 1996 at 5–7, 9, and 111.

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. As noted above, a cogeneration unit is a unit that uses the same energy to produce both thermal energy (heat or steam) that is used for industrial, commercial, or heating or cooling purposes; and electricity. 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). Non-cogeneration units involved in electricity sales could be utility units regardless of whether the non-cogeneration units met one-third potential electrical output capacity/25 MWe criteria.

Finally, 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 hazardous air pollutants listed in section 112(b) apply generally to stationary sources. However, such emission limits will apply to ''electric utility steam generating units'' only if the Administrator makes a specific finding after considering the results of a required study. In particular, section 112(n)(1)(A) requires the Administrator to study ''the hazards to public health reasonably anticipated to occur as a result of emissions by electric utility steam generating units'' of the listed pollutants ''after imposition of the requirements of [the Clean Air Act]'' (42 U.S.C. 7412(n)(1)(A)). That section further provides that the Administrator ''shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is appropriate and necessary after considering the results of the study.'' *Id.* Thus, in general, cogeneration units excluded from the definition of ''electric utility steam generating unit'' are subject by statute—without any study or finding by the Administrator—to the requirements for regulation of hazardous air pollutants under section 112, while cogeneration units included in that definition only become subject to section 112 based on the Administrator's study and finding supporting regulation of units meeting that definition. (*See* 64 FR 63025, 63030; November 18, 1999) (Table 1, showing schedule for promulgation of standards for sources (i.e., industrial boilers and institutional/commercial boilers) of hazardous air pollutants). See also 65 FR 79825, December 20, 2001 [Administrator's finding under section 112(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'' regulation under some provisions and ''less'' or ''later'' regulation under other provisions.

2. What Is 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 of the ''cogeneration exclusion.'' Under the methodology applied to all units, after determining the date on which a unit commenced operation (*e.g.,* commenced combustion of 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 [7] for classifying all units (including cogeneration units) in the States subject to the NO_X SIP Call as EGUs or non-EGUs (63 FR 71223, December 24, 1998). We applied this methodology to cogeneration units and not the one-third potential electrical output capacity/25MWe sales criteria of the ''cogeneration exclusion.'' *See id.*

(a)(i) For units that commenced operation before January 1, 1996, we classified as an EGU any unit that sells 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 that commenced operation before January 1, 1996, we classified as a non-EGU any unit that did not produce electricity for sale under firm contract to the grid.

[7] The numbering of the steps in the methodology is added for the convenience of the reader.

[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). As discussed below, we propose to adopt in today's proposed rule 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).

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

(iv) For units that commenced operation on or after January 1, 1996, we classified as non-EGUs the following units: any unit not serving a generator that produces electricity for sale; or any unit serving a generator that has a nameplate capacity equal to or less than 25 MWe, that produces electricity for sale, and that has the potential to use 50 percent or less of the usable energy of the boiler or turbine. In the December 24, 1998 supplemental action, we did not define the term ''usable energy.'' [9]

(b)(i) For a unit classified [under paragraph (a)(i) or (a)(iii) above] as an EGU, 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 [under paragraph (a)(ii) or (a)(iv) above] as a non-EGU, 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 71220, 71224, December 24, 1998 (explaining procedures used if data on boiler heat input capacity were not available). In the December 24, 1998 supplemental action, we did not expressly define the term ''maximum design heat input.'' [11]

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 failed to apply this particular exclusion for cogenerators that petitioners challenged in *Michigan.*

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

In today's rulemaking, we are addressing three aspects of the EGU definition. First, for purposes of the NO_X SIP Call and the Section 126 Rule, we are proposing not to apply to cogeneration units the one-third potential electrical output/25 MWe sales criteria of the ''cogeneration exclusion'' in classifying the units as EGUs or non-EGUs. Under today's proposal, we would apply to all units, including cogeneration units, 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. We are proposing to change the categorization of units under the NO_X SIP Call definition of EGU (set forth in section II.A.2 above) as units commencing operation before January 1, 1996 or units commencing operation on or after January 1, 1996. Under today's proposal, we would instead categorize units as units commencing operation before January 1, 1997, units commencing operation on or after January 1, 1997 and before January 1, 1999, or units commencing operation on or after January 1, 1999 for purposes of classifying units as EGUs or non-EGUs. 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 and, under today's proposal, units are classified the same way as in the January 18, 2000 Section 126 final rule. We are also proposing to adopt the term ''potential electrical output capacity'' and the 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'' used in the January 18, 2000 Section 126 Rule. As noted above, these changes to conform to the January 18, 2000 Section 126 Rule do not affect the budgets that were established under the final NO_X SIP Call and the Technical Amendments.

The only aspects of the EGU definition that we are addressing in today's rulemaking are: the use, for cogeneration units, of the generally applicable methodology for EGU/non-EGU classification rather than the ''cogeneration exclusion'' criteria; the changes in categories of units based on commencement of operation date; and the adoption of a new term and new definitions of terms. The changes to aspects of the EGU definition result in corresponding changes to aspects of the non-EGU definition. These aspects of the EGU and non-EGU definitions are discussed in detail below and are the only issues related to EGU and non-EGU definition on which we are requesting comment today. We are not reconsidering, and are not taking comment on, any other aspects of the EGU or non-EGU definitions.

a. Use of the same EGU/non-EGU classification methodology for cogeneration units as for all other units

We believe that it is appropriate to apply to cogeneration units the same methodology for EGU/non-EGU classification as applied to all other units and not to apply the one-third electrical potential output capacity/25 MWe sales criteria in order to classify cogeneration units as EGUs or non-EGUs. This is appropriate because the reasons for distinguishing between utilities and non-utilities no longer exist in light of the dramatic changes that have occurred in the electric power industry since 1990 due to the emergence of competitive markets for electricity generation in which non-utility generators compete to an increasingly significant extent with utilities. As a result, the historical difference between utilities and non-utilities is increasingly blurred and irrelevant in determining what units are involved in, and should be classified as, producing and selling electricity. In addition, there are no physical, operational, or technological differences that warrant use of a different EGU/non-EGU classification methodology for cogeneration units than for other units.

[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 long-standing definition of the latter term as ''33 percent of a unit's maximum design heat input'' (65 FR 2694 and 2731). As discussed below, we propose to adopt in today's proposed rule 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_XSIP Call (63 FR 57356, 57514–38) 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.'' As discussed below, we propose to adopt in today's proposed rule 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).

[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.'' As discussed below, we propose to adopt in today's proposed rule the same definition used in the January 18, 2000 Section 126 final rule.

i. Distinction between units in the electric generation business and units in the industrial sector

As discussed above, 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 proposal, 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 (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.

While we are using in today's proposal the long-standing approach of distinguishing between units in the electric generation business and units in the industrial sector, we are proposing to use the revised definition of EGU (i.e., the EGU definition in the Section 126 Rule) in order to reflect recent changes in the electric generation business and the types of units that currently participate in that business. As discussed below, that business is no longer confined essentially to utilities, and non-utilities are playing an increasingly significant role. We are proposing to define EGU in a way that includes both utilities and non-utilities that are in that business and to not apply criteria to cogeneration units (*i.e.*, the one third potential electrical output capacity/25 MWe sales criteria) that tend to exclude non-utilities from the EGU category.

ii. Effect of electricity competition and electric power restructuring on distinction between utilities and non-utilities

The development of competitive electricity markets is ongoing:

> Propelled by events of the recent past, the electric power industry is currently in the midst of changing from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Advances in power generation technology, perceived inefficiencies in the industry, large variations in regional electricity prices, and the trend to competitive markets in other regulated industries have all contributed to the transition. Industry changes brought on by this movement are ongoing, and the industry will remain in a transitional state for the next few years or more. *The Changing Structure of the Electric Power Industry: Selected Issues, 1998,* Energy Information Administration, July 1998 at ix.

See also The Changing Structure of the Electric Power Industry: An Update 35–38 (discussing the factors underlying the ongoing development of competitive electricity markets and restructuring of the electric power industry). Because of the ongoing development of electricity markets and electric power industry restructuring, competition in electric generation is expected to become more pervasive in the future. *Electric Power Annual 1998*, Vol. II, Energy Information Administration, December 1998 at 1 and 4.

With increased competition and industry restructuring, both utilities and non-utilities are generating and selling significant amounts of electricity, a trend that is likely to increase in the future. In particular, the increasing role of non-utilities is reflected in electric power data for the period 1992–1998 indicating that:

(1) The number of investor-owned utilities has decreased by nearly 8 percent, while the number of non-utilities has increased by over 9 percent.

(2) Non-utilities are expanding and buying utility-divested generation assets, causing their net generation to increase by 42 percent and their nameplate capacity to increase by 72 percent from 1992 to 1998. Non-utility capacity and generation will increase even more as they acquire additional utility-divested generation assets over the next few years.

(3) The non-utility share of net generation has risen from 9 percent (286 million megawatt hours) in 1992 to 11 percent (406 million megawatt hours) in 1998.

(4) Utilities have historically dominated the addition of new capacity but additions to capacity by utilities are decreasing while additions by non-utilities are increasing. In the period 1985–1991, utilities were responsible for 62 percent of the industry's additions to capacity, but that figure dropped to 48 percent in the period 1992–1998. *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations,* Energy Information Administration, December 1999 at x.

In fact, in 1998 alone, non-utilities accounted for about 11 percent of net generation and 81 percent of capacity additions. *Id.* at 8 (Figure 1); *see also id.* at 9–10 [Figure 2 (graph showing non-utility megawatt additions to capacity far exceeding utility additions) and Figure 3 (graph showing non-utility annual growth rate of additions to capacity far exceeding utility annual growth rate of additions)]. Cogeneration units currently account for about 55 percent of existing non-utility capacity, and there is a large potential for more cogeneration, e.g., in both the refining and paper and pulp industries. *Electric Power Annual 1998*, Vol. II at 10.

Along with increases in non-utility generation and capacity, non-utility sales of electricity to utilities and to end-users have increased during 1994–1998, even though the vast majority of electricity sales are still made by utilities. *Id.* at 87 [Table 51 (showing sales to utilities and end-users)]. With increasing competition and restructuring, any unit serving a generator—regardless of whether the unit owner is a utility or a non-utility (e.g., an independent power producer or an industrial company)—can produce and sell electricity. As a result, ''new entrants, generating and selling power, have made inroads in an industry previously closed to outside participants. Because of this array of changes, the industry is now more commonly called the *electric power industry* rather than the erstwhile *electric utility industry.'' The Changing Structure of the Electric Power Industry: Selected Issues, 1998* at 5. See also *The Changing Structure of the Electric Power Industry 2000: An Update,* Energy Information Administration, October 2000 at 1 and Supporting Statement for the Electric Power Surveys, OMB Number 1905–0129, Energy Information Administration, September 2001 at 7 (discussing the continued trend of increased participation of non-utilities in electric power industry). Particularly, in light of increasing non-utility capacity additions and sales and the likelihood of continued growth in non-utility participation in competitive electricity markets, distinctions based on ownership of units are becoming less important. These distinctions are increasingly irrelevant in determining whether units are involved in, and should be classified as, producing and selling electricity.

The Energy Policy Act of 1992 encouraged these types of changes in the electric power industry by recognizing a new category of non-utility generators under the Public Utility Holding Companies Act, *i.e.,* ''exempt wholesale generators,'' which lack transmission facilities and are exempt from the corporate and geographic restrictions imposed by the Public Utility Holding Companies Act. Exempt wholesale generators may generally charge market-based rates but cannot require utilities to purchase the electricity. *The Changing Structure of the Electric Power Industry: An Update* at 28–29. The Energy Policy Act also amended section 211 of the Federal Power Act to broaden the ability of non-utility generators to request that the Federal Energy Regulatory Commission (FERC) order utilities to provide transmission services for electricity produced and sold by non-utility generators, *e.g.,* transmission access to non-contiguous utilities. *The Changing Structure of the Electric Power Industry: Selected Issues, 1998* at 1. In response to the Energy Policy Act, FERC has encouraged competition for electricity at the wholesale level (i.e., in sales of electricity for resale) by removing obstacles to such competition. For example, starting in 1996, FERC issued orders [e.g., Order No. 888, 61 FR 21540 (1996), and Order No. 889, 61 FR 21737 (1996)] requiring utilities to provide open access for electricity generators to transmission lines, file nondiscriminatory open-access tariffs applicable to all parties seeking transmission service, and participate in the Open Access Same-Time Information System (OASIS). *Id.; see also* The Changing Structure of the Electric Power Industry: An Update at 57–63 (describing FERC Order Nos. 888 and 889). The FERC is continuing to take actions aimed at ensuring open transmission access. *See, e.g.,* Order No. 2000, 65 FR 809 (2000) (requiring utilities to submit proposals for participation in a regional transmission organization meeting specified requirements aimed at removing impediments to electricity competition or to submit any plans to work toward such participation). In short, future Federal actions promoting wholesale competition and deregulation of electricity generation will likely continue the process of removing the distinction between utilities and non-utilities.

In some States, State actions may also continue this process. Many States have adopted legislation or approved plans for, or have begun to consider providing, access by end-users to competitive electricity markets. A number of States have adopted pilot programs to initiate and evaluate the feasibility of competition at the retail level (i.e., in sales of electricity to end-users). *See Electric Power Annual 1998,* Vol II at 4; and *The Changing Structure of the Electric Power Industry: Selected Issues,* 1998 at xi and 93. Consequently, ''[o]ne of the expectations for the future is that end users of electricity will be allowed to participate in a unified wholesale/retail market.'' *Id.* at 3. *See also The Changing Structure of the Electric Power Industry: An Update* at 67–68 (describing State actions).

Other Federal agencies that deal with the power industry have realized that the historical distinction between utilities and non-utilities is no longer meaningful. In particular, the EIA is in the process of revising its reporting requirements so that there will be virtually no distinction between reporting by utility generators and by non-utility generators. Historically, EIA required utilities to report electricity generation, fuel use, and other information on different forms than non-utilities and treated the utility information as public information and the non-utility information as confidential business information. Recently, EIA began an effort to reduce, and virtually eliminate, the differences between utility and non-utility forms and to make most information available to the public. *See* Electric Power Surveys Supporting Statement, EIA, November 1998 at 6, 26, 28–9, 47, 50 and Supporting Statement for the Electric Power Surveys, OMB Number 1905–0129 at 16–17, 28, and 30 (explaining that utilities and non-utilities will be subject to the same data collection and disclosure policies).

In summary, the increasingly competitive nature of the electric power industry and the significant and increasing participation of non-utilities in competitive electricity markets support similar treatment of utilities and non-utilities. We believe 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.

iii. Differences between the design and operation of cogenerating units and non-cogenerating units

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 at average costs, similar to those achieved by non-cogeneration units. Similarly, 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.

Cogeneration units operate in two basic configurations.[12] 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 can be 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 can be 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 to the heat recovery steam generator which 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 electrical power. 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-*

[12] 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 # A–96–56, item # 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.

Cycle Product Line and Performance, GE Power Systems, October 2000, docket # A–96–56, item 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 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, rather than electricity generation.

Further, in comparison to a non-cogeneration system that generates electricity for sale, either type of cogeneration system looks essentially the same except for the addition of valves and piping to send the steam for process use or heating and cooling. Under 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. [For examples and discussion of how post-combustion controls apply to cogeneration units, see docket # A–96–56, item # XII–L–02; XII–L–03; and XII–L–05 at 10–11 and 13 (Figure 15).]

More specifically, as discussed in detail in the technical support document (Lack of Relevant Physical or Technological Differences Between Cogeneration Units and Utility Electricity Generating Units, September 25, 2000, docket # A–96–56, item # XII–K–47), 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 above 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 systems have been used at a wide range of temperatures (*e.g.,* from 1250 degrees F to 2600 degrees F) and have 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. Selective catalytic reduction has been demonstrated on a wide range of boiler types and sizes and on combined cycle systems. The SCR systems have been used at a wide range of temperatures (*e.g.,* 450 degrees F to 1100 degrees F) and have been designed to handle a wide range of load variation.

Therefore, the same, proven post-combustion NO_X control technologies (SNCR and SCR) are applicable to non-cogeneration units producing electricity for sale and to cogeneration units producing electricity for sale. Because no relevant physical, operational, or technological differences between these groups of units exist and because the post-combustion NO_X control technologies are located in the same place and operated in the same manner, we maintain that there is no significant difference in the average cost of controlling NO_X emissions from these units.

For example, 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 # A–96–56, item # V–C–03 at A5–7 (Table A5–5). The record also shows that SCR on a new coal-fired cogeneration unit has a capital cost of $58 per kilowatt. *See Status Report on NO_X Control Technologies and Cost Effectiveness for Utility Boilers*, NESCAUM and MARAMA, June 1998, docket # A–96–56, item # VI–B–05 at 151–53. EPA maintains that this cost is reasonably consistent with the average cost that EPA determined for all EGUs.[13]

Therefore, we conclude that the cost estimates we made for NO_X control technology retrofits apply to both cogeneration and non-cogeneration units producing electricity for sale. In today's rulemaking, we request 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. Any cost information that is provided must have sufficient detail and support to allow evaluation as to whether the unit involved represents a typical unit.

4. What Methodology Are We Using To Classify EGU/Non-EGU Cogeneration Units?

For the reasons set forth above in section II.A.3 of today's preamble, we believe that it is appropriate to use the same methodology to classify all units, including cogeneration units, as EGUs or non-EGUs and generally to classify as EGUs all units that generate electricity for sale. This is appropriate regardless of whether the owners or operators of the units generating electricity for sale are utilities or non-utilities. Since the one-third potential electrical output capacity/25 MWe sales criteria of the ''cogeneration exclusion'' are essentially proxies for distinguishing between utility and non-utility ownership of cogeneration units, those criteria are no longer appropriate for distinguishing between EGUs and non-EGUs and classifying cogeneration units as EGUs or non-EGUs. In addition, as also identified in section II.A.3 above, we believe there are no relevant physical, operational, or technological differences between cogeneration and non-cogeneration units producing electricity for sale.

However, in order to provide a transition for units commencing operation before the development of competitive electricity markets or as these markets were emerging, we propose to apply to cogeneration units commencing operation before January 1, 1999 a transitional criterion for EGU/non-EGU classification. This is the same criterion that was used in the September

[13] 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.

24, 1998 NO_X SIP Call Rule. Specifically, for cogeneration units commencing operation before January 1, 1999, we will classify as EGUs units that generate electricity for sale under firm contract to the grid. Cogeneration units that generate 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), will be classified as non-EGUs. For cogeneration units commencing operation on or after January 1, 1999, we will generally classify as EGUs all cogeneration units that generate electricity for sale, with the limited exception discussed below. As also discussed below, this is the same approach that is used for classifying units that are not cogeneration units.

We believe that the firm-contract criterion provides a reasonable transitional means of making the EGU/non-EGU classification for cogeneration units. As discussed above, with electricity competition and power industry restructuring, the distinction between utility and non-utility ownership, and thus the one-third potential electrical output capacity/25 MWe sales criteria, no longer provides a relevant means of distinguishing between EGUs and non-EGUs. Further, application of the one-third potential electrical output capacity/25 MWe sales criteria requires historical data for each cogeneration unit on the unit's electrical output capacity and electrical sales, all of which data has been treated by cogeneration unit owners and EIA as confidential business information. We do not have, and the petitioner and commenters in the NO_X SIP Call and Section 126 rulemakings have never provided, complete information on the identification of all units claiming to be cogeneration units and on such units' historical capacity and actual generation and sales.

In contrast, 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. Moreover, the historical information necessary to apply the firm-contract criterion to cogeneration units (and other units) is already available to us. As discussed above, 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.

Application of the firm-contract criterion results in classifying, as EGUs, cogeneration units that commenced operation before January 1, 1999 and whose owners have committed to providing electricity for sale from the units. This criterion reflects the fact that the amount or percentage of the sales (which is a proxy for utility vs. non-utility ownership) is no longer relevant for EGU/non-EGU classification. The criterion is also practical for us to apply. For cogeneration units commencing operation on or after January 1, 1999, we will generally classify as EGUs all units generating electricity for sale, regardless of whether the sales are sales under firm contract to the grid. The category of cogeneration units recently commencing operation is relatively small. In the future, EIA will likely be treating virtually all new data for both utilities and non-utilities as public information, even though EIA will continue to keep historical non-utility data confidential. We, therefore, believe it is practical for us or States to obtain electricity sales information for such cogeneration units.

a. Difference in treatment of cogeneration units that produce electricity for sale and those that produce electricity for internal use only.

In the May 15, 2001 decision in the Section 126 case, the D.C. 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. EPA notes 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.[14] As previously discussed, this is a long-standing approach that, for the reasons presented above, EPA is continuing to use in the NO_X SIP Call and Section 126 Rule. EPA recognizes that this may result in units that are physically identical being regulated differently simply based on whether or not electricity produced by the unit is sold. 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—EPA believes that it is prudent to gain experience in operating the trading program under the NO_X SIP Call and Section 126 Rule. EPA proposes to take a reasonable first step to take account of electric restructuring and deregulation by revising the definition of EGU to focus on production of electricity for sale, regardless of whether a unit is a utility or a non-utility. After EPA has gained experience with the NO_X SIP Call and Section 126 trading program, EPA intends to consider whether to take the additional step of treating the same all units that produce electricity, whether for sale or internal use.

b. Minor revisions to NO_X SIP Call definition of EGU.

i. As noted above, we propose to change the categorization of units used in the NO_X SIP Call from units commencing operation before January 1, 1996 or units commencing operation on or after January 1, 1996 to units commencing operation before January 1, 1997, units commencing operation on or after January 1, 1997 and before January 1, 1999, or units commencing operation on or after January 1, 1999. We propose to use these new categories in applying the firm-contract criterion for EGU/non-EGU classification of all units, including cogeneration units. This is a modification of the methodology that has been used in the NO_X SIP Call. This modification is set forth above in section II.A of today's preamble. Under today's action, for units commencing operation before January 1, 1997, we propose to use the same period (i.e., 1995–1996) to determine the EGU/non-EGU classification of the units as we used to calculate the EGU portion of each State's budget under the NO_X SIP Call. *See* 63 FR 57407, October 27, 1998. Whether such a unit had electricity sales under firm contract to the grid in 1995–1996 will be used to determine the unit's EGU/non-EGU classification.

For units commencing operation on or after January 1, 1997 and before January 1, 1999, we propose to use 1997–1998 to determine the EGU/non-EGU classification of units. Whether such a unit had electricity sales under firm contract to the grid in 1997–1998 determines the unit's EGU/non-EGU classification.

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

The firm-contract criterion will not apply to 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 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.

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 any electricity sales. First, information is available to us on firm-contract electricity sales on a calendar year basis only. Consequently, the classification of units based on whether the generators 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, 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 firm-contract 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.

In the interests of reducing the complexity of the regulations aimed at reducing interstate transport of ozone, we believe that it is desirable to have consistent EGU definitions in the NO_X SIP Call and Section 126 programs. With the above-described changes in the categories of units based on commencement-of-operation date, the EGU definition in the NO_X SIP Call will be the same as the EGU definition reflected in the applicability provisions (*i.e.,* § 97.8(a)) of the Section 126 program.

ii. As noted above, we also propose to 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.

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

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. This comment and the failure of commenters to identify any specific cogeneration units affected by today's proposed change suggest that use of the one-third potential electrical output capacity/25 MWe sales criteria, instead of the classification proposed in today's rule, would shift few, if any, existing cogeneration units from being large EGUs to being large or small non-EGUs.

The EGU/non-EGU classification methodology that we propose to use for most existing cogeneration units is based on whether, during a specified period, the unit served a generator that sold electricity under firm contract to the grid. The specified period for units commencing operation before January 1, 1997 is 1995–1996, and the specified period for units commencing operation on or after January 1, 1997 and before January 1, 1999 is 1997–1998. Since the EGU/non-EGU classification is based on sales under firm contract and not simply sales, the methodology proposed for cogeneration units does not classify as EGUs all existing cogeneration units that generate electricity for sale. We believe that existing cogeneration units that are not significantly involved in the business of generating electricity for sale will be classified under the proposed methodology as non-EGUs, rather than EGUs, because the owners of such units will not have committed to providing electricity for sale from the units.

We request commenters to identify by name, location, and plant and point identification any cogeneration unit that commenters believe would be classified as an EGU under today's proposed methodology and would be classified as a non-EGU if the one-third potential electrical output capacity/25 MWe sales criteria were applied instead of the proposed methodology. Further, we request that commenters also state whether the unit is large or small under each such classification approach and provide information about each such unit, supporting any claimed EGU, non-EGU, large, and small classifications of the unit.

While we believe that today's proposed methodology will classify as non-EGUs existing cogeneration units that are not significantly involved in the business of generating electricity for sale, we request information about whether adopting the one-third potential electrical output capacity/25 MWe sales criteria, instead of the proposed methodology, would change the classification for some cogeneration units in a way that would make them potentially subject to more stringent emission reduction requirements than under the proposed methodology. For example, an existing cogeneration unit classified as a large non-EGU under today's proposed methodology may become a large EGU if the unit did not sell electricity under firm contract to the grid, but sold more than one-third of its potential electrical output capacity and serves a generator with a nameplate capacity larger than 25 MWe. By further example, an existing cogeneration unit classified as a small EGU under today's proposed methodology may become a large non-EGU if the unit sold electricity under firm contract to the grid, but sold less than one-third of its potential electrical output capacity and has a maximum design heat input of greater than 250 mmBtu/hr.

We request commenters to identify by name, location, and plant and point identification any cogeneration unit that commenters believe would be classified as a large or small non-EGU under today's proposed methodology and that would be classified as a large EGU if the one-third potential electrical output capacity/25 MWe sales criteria were applied instead of the proposed methodology. We also request commenters to identify by name, location, and plant and point identification any cogeneration unit that the commenters believe would be classified as a small EGU under today's proposed methodology and that would be classified as a large non-EGU if the one-third potential electrical output capacity/25 MWe sales criteria were applied instead of the proposed methodology. In addition, we request that commenters also provide information about each identified unit supporting any claimed EGU, non-EGU, large, or small classifications of the unit.

Sources that identify themselves as cogenerators or small cogenerators (one-third potential electrical output capacity/25 MWe sales criteria) should submit the following information to assist us in confirming 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, sources 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 concerning the unit's maximum design heat input.

Under today's proposed methodology, the EGU definition based generally on whether the unit has any electricity sales will apply to units that commence operation on or after January 1, 1999. Thus, in general, any new units that serve generators involved in generating electricity for sale will be EGUs. This reflects the restructuring of the electric power industry under which any unit serving a generator (regardless of whether the owner is a utility or a non-utility) can be involved in selling electricity and non-utility units are involved in an increasing portion of the electricity market. Since we are classifying as EGUs cogeneration units that commence operation on or after January 1, 1999 and sell any electricity, this may result in classification as EGUs of some cogeneration units that recently commenced operation or commence operation in the future and that would be non-EGUs under the one-third potential electrical output capacity/25 MWe sales criteria. As discussed above, we maintain that this result is reasonable in light of today's changing electricity markets and power industry restructuring.

B. What Control Level Is Being Proposed for Stationary Reciprocating Internal Combustion Engines (IC Engines)?

1. What Control Level Was Used in the NO_X SIP Call?

In developing budgets for the NO_X SIP Call proposal (62 FR 60318, November 7, 1997), we assumed a 70 percent reduction at large sources and reasonably available control technology (RACT) at medium-sized sources (the OTAG recommendation) for about 20 categories of non-EGU stationary sources. These sources included, among others, industrial boilers and turbines, cement kilns, glass manufacturing, IC engines, sand and gravel operations, and steel manufacturing. Once State NO_X budget components were established for a particular option, control strategies were developed for the least-cost solution to attain these budgets. The least-cost solution was achieved by assuming controls on over 9,000 NO_X sources of various sizes and categories at an average cost effectiveness of $1,650/ton; two thirds of the NO_X emissions reductions were from only two source categories: non-EGU boilers and IC engines.

In the final NO_X SIP Call Rule, we looked at applying a size cut-off for small sources and considered various control levels for each of the categories of large non-EGU stationary sources. We determined that highly cost-effective controls for non-EGUs were appropriate for only three categories: large industrial boilers and turbines, cement kilns, and IC engines. For large IC engines, we determined, based on the relevant Alternative Control Techniques (ACT) document, [15] that post-combustion controls are available that would achieve a 90 percent reduction from uncontrolled levels at costs well below $2,000 per ton. Therefore, the budget calculations included a 90 percent decrease for large IC engines.

2. What Was the March 3, 2000 Court Decision Regarding IC Engines?

In the litigation on the NO_X SIP Call, the Interstate Natural Gas Association of America (INGAA), a trade association that represents major interstate natural gas transmission companies in the United States, contended that we did not provide adequate notice and opportunity to comment on the control level assumed for IC engines in its determination of State NO_X budgets for the final rule. In *Michigan* v. *EPA*, 213 F.3d at 693, the Court agreed and remanded this issue to us for further consideration.

The INGAA further contended that the documents that we relied on did not support our assumption of 90 percent control level. In remanding due to inadequate notice, the Court did not rule on the merits of the issue, i.e., the level of control for IC engines.

In addition, INGAA challenged our definition of ''large'' IC engine.[16] The Court, however, upheld the Agency's definition of large IC engine, stating that we went through an extensive comment period on this issue. *Id.* at 693–94.

3. What Are the Emissions From IC Engines?

The large IC engines affected by the NO_X SIP Call are primarily used in pipeline transmission service with gas turbines at compressor stations. Uncontrolled NO_X emissions from large IC engines are, on average, greater than 3.0 lbs/mmBtu and uncontrolled NO_X emissions from gas turbines are about 0.3 lbs/mmBtu. In the NO_X SIP Call, we determined that highly cost-effective controls are available to reduce emissions from large IC engines by 90 percent from uncontrolled levels (i.e., to about 0.3 lbs/mmBtu); [17] and that NO_X

[15] Alternative Control Techniques document, ''NO_X Emissions from Stationary Reciprocating Internal Combustion Engines,'' EPA–453/R–93–032, July 1993.

[16] A large IC engine is one that emitted, on average, more than 1 ton per day during the 1995 ozone season (May 1 through September 30).

[17] The discussion in the text generally uses ''grams/brake horsepower-hour'' or g/bhp-hr rather than lbs/mmBtu since the former is the convention for the industry. The uncontrolled estimate of 3.0 lbs/mmBtu (from AP–42, October 1996) corresponds to about 11.3 g/bhp-hr. The 1993 ACT

emissions from large gas turbines (and boilers) can be decreased by highly cost-effective controls to an average regionwide emission rate of 0.15–0.17 lbs/mmBtu.[18]

In the September 24, 1998 final NO_X SIP Call Rule, we identified about 300 large IC engines. Subsequently, we received information from commenters seeking to make changes to the emissions inventory. We made corrections to the emissions inventory which now includes about 200 large IC engines in the final NO_X SIP Call budget (65 FR 11222). The vast majority of large IC engines included in the budget are natural gas fired.

4. What Control Technologies Are Available for IC Engines?

For the NO_X SIP Call, we divided IC engines into four categories and assigned (for purposes of the budget calculation) a 90 percent emissions decrease on average to each category. The 90 percent decrease was based on information in our ACT document for IC engines and application of the following controls: non-selective catalytic reduction (NSCR) for natural gas-fired rich-burn engines and SCR for diesel, dual-fuel, and natural gas-fired lean-burn engines.

As described in detail in the ACT document, several other control technologies are available to decrease emissions of NO_X from IC engines. For natural gas-fired rich-burn engines, the following additional controls exist: air/fuel adjustment, ignition timing retard, ignition timing retard plus air/fuel adjustment, prestratified charge, and low-emission combustion. For diesel engines, ignition timing retard can also be used to reduce emissions of NO_X. For dual-fuel engines ignition timing retard and low-emission combustion are available. Finally, for natural gas-fired lean-burn engines, the following additional controls exist: air/fuel adjustment, ignition timing retard, ignition timing retard plus air/fuel adjustment, and low emission combustion. These controls technologies vary in terms of cost, effectiveness, additional fuel needed, and impact on power output.

The NO_X SIP Call budgets were calculated by applying controls described in the ACT document for IC engines that represented the greatest emissions reductions that would be achieved by applying available, highly cost-effective controls. For natural gas-fired rich-burn IC engines, NSCR provides the greatest NO_X reduction of all the highly cost-effective technologies considered in the ACT document and is capable of providing a 90 to 98 percent reduction in NO_X emissions. For diesel and dual-fuel engines, SCR provides the greatest NO_X reduction of all highly cost-effective technologies considered in the 1993 ACT document and is reported to provide an 80 to 90 percent reduction in NO_X emissions. More recent reports state that NO_X emissions can be reduced by greater than 90 percent by SCR. Therefore, we estimate NO_X reductions for these engines at 90 percent on average. We estimate the population of diesel/dual fuel IC engines is a very small part of the large IC engines population in the NO_X SIP Call (less than 3 percent).

In addition to being highly cost effective and providing greater emission reductions, the above selected controls generally have the advantage of requiring less additional fuel and have less adverse impact on power output. For example, ignition retard and air-fuel ratio adjustment requires the use of up to 7 percent additional fuel and prestratified charge technology may reduce power output up to 20 percent. In contrast, NSCR and SCR technologies require additional fuel in the range of 0.5 to 5 percent and may reduce power output only in the 1 to 2 percent range.

For all large IC engines, except natural gas-fired lean-burn engines (see discussion below on lean-burn engines), we continue to believe that 90 percent control is achievable through NSCR or SCR and is highly cost effective—i.e., less than $2000/ton ozone season. This is demonstrated in the ACT document for IC engines and in the IC Engines Technical Support Document (TSD) entitled ''Stationary Reciprocating Internal Combustion Engines Technical Support Document for NO_X SIP Call Proposal,'' EPA, OAQPS, September 5, 2000 (IC Engines TSD). Therefore, we propose to assign a 90 percent emissions decrease on average for large natural gas-fired rich-burn, diesel, and dual-fuel IC engines. We invite comment on all the control technologies listed above, as well as other technologies not listed. The appropriate control technology and percent reduction for natural gas-fired lean-burn engines is discussed later in this action.

The time required from a request for cost proposal to field installation of proposed NO_X controls for IC engines is less than 11 months. Therefore, an implementation deadline of May 31, 2004 is reasonable for States required to adopt and submit Phase II rules no later than April 1, 2003, as well as for Georgia and Missouri.

5. Is SCR an Appropriate Technology for Natural Gas-Fired Lean-Burn IC Engines?

Information received by us from the natural gas transmission industry after publication of the NO_X SIP Call Rule indicates that most, if not all, large natural gas-fired lean-burn IC engines in the SIP Call region are in natural gas distribution and storage service and that these engines experience frequently changing load conditions which make application of SCR infeasible. The industry also states that low emission combustion (LEC) technology is a proven technology for natural gas-fired lean-burn IC engines, while SCR is not. Regarding variable load operations, our ACT document for IC engines states that little data exist with which to evaluate application of SCR for the lean-burn, variable load operations. With the understanding that these large IC engines are in variable load operations, we now believe there is an insufficient basis to conclude that SCR is an appropriate technology for the large lean-burn engines. Therefore, we are no longer proposing that SCR is a highly cost-effective control technology for the natural gas-fired lean-burn IC engines. As described in the next section, we believe LEC technology is a highly cost-effective control technology and is appropriate for natural gas-fired lean-burn IC engines in either variable or continuous load operation.

6. Is LEC Technology Appropriate for Natural Gas-Fired Lean-Burn IC Engines?

Lean-burn engines can reduce NO_X emissions by adjusting the air/fuel ratio to a leaner mode of operation. The increased volume of air in the combustion process increases the heat capacity of the mixture, lowering combustion temperatures and reducing NO_X formation. The LEC technology involves a large increase in the air/fuel ratio (to ultra-lean conditions) compared to conventional designs.

Emissions of NO_X from existing lean-burn engines can vary widely due to the specific air/fuel ratio at which the engine is designed to operate. For naturally aspirated engines (which operate at near stoichiometric air/fuel ratios), emissions can be as high as 26 grams per brake horsepower-hour (g/bhp-hr). Turbo-charged engines can reduce emissions of NO_X up to 40 percent by air/fuel ratio increases. Further, engines designed to operate at very high air/fuel ratios and with

document for IC engines estimates average uncontrolled emissions at 5.13 lb/mmBtu or 16.8 g/bhp-hr.

[18] NO_X SIP Call Rule at 63 FR 57402.

advanced ignition technology can reduce emissions to about 1 g/bhp-hr.

Because there are many types of existing lean-burn engines (e.g., some turbo charged, some not), the retrofit of LEC technology would require different modifications depending on the particular engine. Application of components of LEC technology will yield incremental emissions reductions. Therefore, it is important to carefully define LEC technology. We propose the following definition, which is similar to the description of LEC technology in the ACT document, and invite comments on the definition. Implementation of LEC technology for lean-burn IC engines means:

> The modification of a natural gas-fueled, spark-ignited, reciprocating internal combustion engine to reduce emissions of NO_X by utilizing ultra-lean air-fuel ratios, high energy ignition systems and/or pre-combustion chambers, increased turbo charging or adding a turbo charger, and increased cooling and/or adding an intercooler or aftercooler, resulting in an engine that is designed to achieve a consistent NO_X emission rate of not more than 1.5–3.0 g/bhp-hr at full capacity (usually 100 percent speed and 100 percent load).

The ACT for IC engines and other documents indicate that LEC technology is appropriate for lean-burn engines, continuous or variable load, and is highly cost effective. We believe application of LEC would achieve NO_X emission levels in the range of 1.5–3.0 g/bhp-hr. This is an 82 to 91 percent reduction from the average uncontrolled emission levels, on average, reported in the ACT document. We believe that LEC retrofit kits are available for all large lean-burn IC engines. As described in the IC Engines TSD, emissions test data collected over the last several years indicate that 91 percent of IC engines with installed LEC technology achieved emission rates of 1.5 g/bhp-hr or less. A guaranteed level of 2.0 g/bhp-hr is generally available from engine manufacturers.

Because most of the engines tested actually are below 1.5 g/bhp-hr, even if some engines in the SIP call area were to exceed the 3.0 level, the average emission rate of several engines is still expected to be well within the 1.5 to 3.0 range. That is, while engines that are equipped with LEC technology designed to meet a 1.5 to 3.0 g/bhp-hr standard will generally meet the design goal, the actual results for a particular engine may vary. There is one type of engine model, Worthington engines, that may be particularly difficult to retrofit and which may exceed the 1.5 to 3.0 g/bhp-hr LEC retrofit level. We request comment on where and how many large Worthington engines are in the area covered by the NO_X SIP Call and what average control level should be expected with application of LEC technology for those engines.

a. Can States adopt an LEC technology standard?

States, of course, are not required to adopt technology standard rules nor even to adopt rules to control emissions from IC engines. However, if States choose to use a technology standard for regulating IC engines, we believe it would be appropriate for States to assume an average reduction level for each engine installing this technology for purposes of calculating the State's emission budget.

In many cases, we do not suggest a technology-based standard since an emission rate and continuous emissions monitoring approach can provide more environmental certainty. In this instance, we have data identifying the tonnage baseline for each large IC engine, but we do not have emission rate (or heat input) data for each IC engine. Thus, in order to calculate the budget reduction for IC engines, we must identify a percentage reduction and apply that value to the tonnage baseline in order to calculate the budget reduction for IC engines. In the case of IC engines, a technology standard can be readily translated into a percentage reduction. Further, we believe there is a large amount of consistent test data supporting LEC technology which provides environmental certainty.

b. What is the cost effectiveness for large IC engines using LEC technology?

For the control range of 82 to 91 percent, the average cost effectiveness for large IC engines using LEC technology has recently been estimated to be \$520 to 550/ton.[19] We acknowledge that specific cost-effectiveness values will vary from engine to engine. The key variables in determining average cost effectiveness for LEC technology are the average uncontrolled emissions at the existing source, the projected level of controlled emissions, annualized costs of the controls, and number of hours of operation in the ozone season. The ACT document uses an average uncontrolled level of 16.8 g/bhp-hr, a controlled level of 2.0 g/bhp-hr, and nearly continuous operation in the ozone season. We believe the ACT document provides a reasonable approach to calculating cost effectiveness for LEC technology. Further, we believe the cost-effectiveness analysis should use updated annualized cost data as described in the IC Engines TSD. For additional information, we analyzed alternative uncontrolled and controlled levels, hours of operation, and annualized costs (see IC Engines TSD). The sensitivity analysis indicates a range of cost effectiveness for large IC engines using LEC technology of \$510 to 870/ton (ozone season).

7. What NO_X SIP Call Budget Calculations Are We Proposing?

We propose 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 propose 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 LEC technology, and consideration of comments received in response to the proposal, we intend to determine a percent reduction number to use in calculating this portion of the NO_X SIP Call budget decrease; the reduction is likely to be within the 82 to 91 percent range. The average cost effectiveness for all large IC engines in the SIP Call population is estimated to be \$530/ton ozone season, where LEC technology is assigned an 87 percent reduction and SNCR and SCR achieve 90 percent reduction.[20] The Agency invites comment on the control level and associated cost-effectiveness calculations with respect to all IC engine types, and we are especially interested in comments regarding the natural gas-fired lean-burn IC engines.

The NO_X SIP Call emissions inventory identifies natural gas-fired IC engines, but does not separate rich- and lean-burn IC engines. In the final rulemaking, if we choose to use different control levels for rich- and lean-burn IC engines, as proposed above, it would be necessary to estimate the emissions in each category in order to calculate the emissions reductions. We propose to assume that two-thirds of the emissions from large natural gas-fired IC engines are from lean-burn operation and one-third is from rich burn. We invite comments on this estimate.

[19] ''NO_X Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NO_X SIP Call States'' prepared by Pechan-Avanti Group for EPA, August 11, 2000; annual costs in 1990 dollars per NO_X tons reduced in the ozone season.

[20] ''NO_X Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NO_X SIP Call States'' prepared by Pechan-Avanti Group for EPA, August 11, 2000.

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

Georgia and Missouri industry petitioners challenged our decision to calculate NO_X budgets for these two States based on the entirety of NO_X emissions in each State. The petitioners maintained that the record supports including only eastern Missouri and northern Georgia as contributing to downwind ozone. The challenge from these petitioners generally stems from the OTAG recommendations. The OTAG recommended NO_X controls to reduce transport for areas within the ''fine grid,'' but recommended that areas within the ''coarse grid'' not be subject to additional controls, other than those required by the CAA. This was based on OTAG's modeling analysis. The OTAG recommendation on Utility NO_X Controls was approved by the Policy Group, June 3, 1997 (62 FR 60318, Appendix B, November 7, 1997).

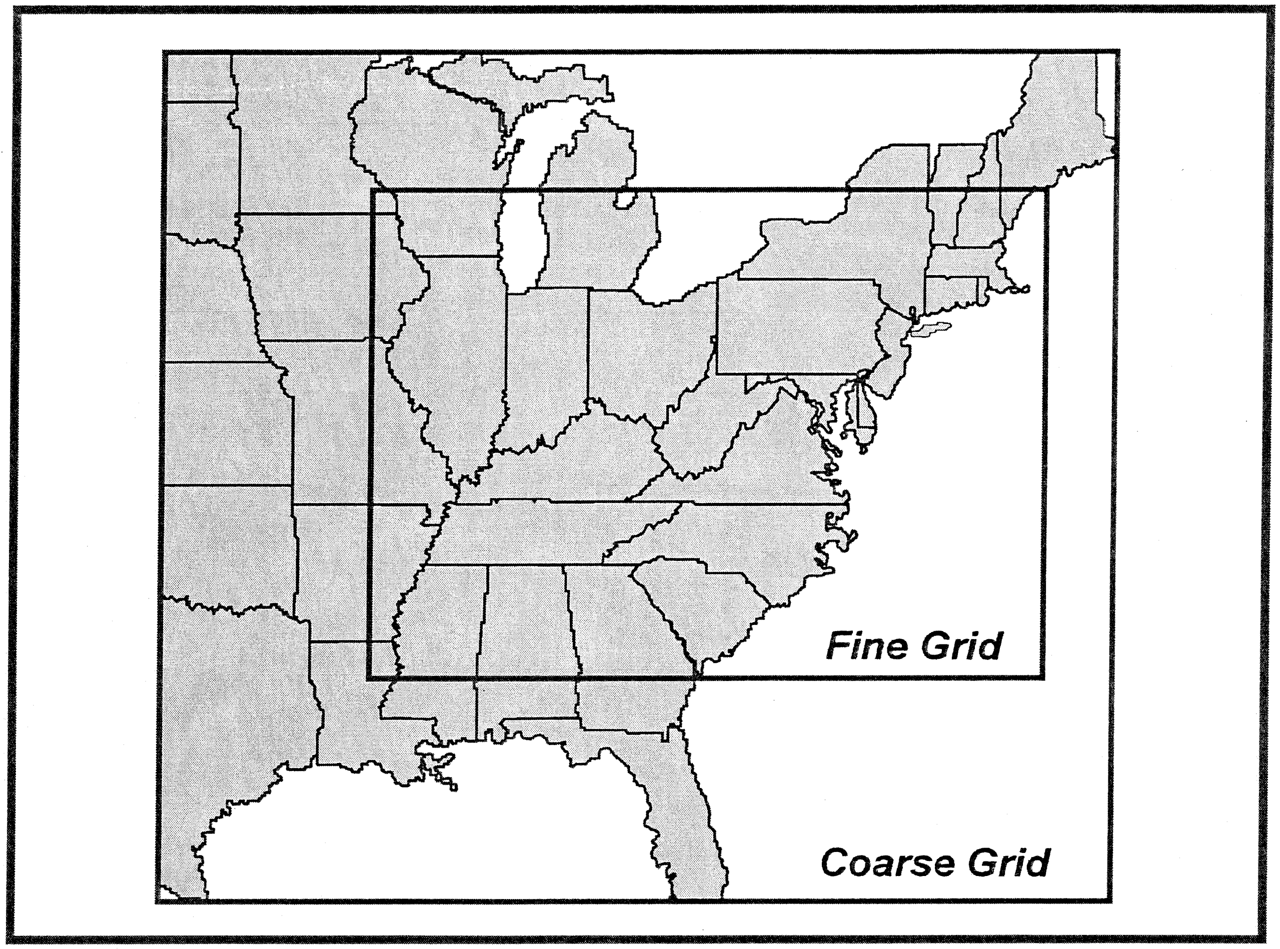
The Court vacated our determination of significant contribution for all of Georgia and Missouri. *Michigan* v. *EPA,* 213 F.3d at 685. The Court did not seem to call into question the proposition that the fine grid portion of each State should be considered to make a significant contribution downwind. However, the Court emphasized that ''EPA must first establish that there is a measurable contribution,'' *id.* at 684, from the coarse grid portion of the State before determining that the coarse grid portion of the State significantly contributes to ozone nonattainment downwind. Elsewhere, the Court seemed to identify the standard as ''material contribution []'' *id.*

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 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.[21] (OTAG Technical Supporting Document, Chapter 2, pg. 6; *www.epa.gov/ttnotag/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.

[21] In addition to these two 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.

Figure 1: OTAG Modeling Domain



The analysis OTAG conducted found that emissions controls examined by OTAG, 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.[22]

Based on OTAG's modeling and recommendations, the technical record for our final NO_X SIP Call rulemaking, and emissions data, we believe that emissions in the fine grid portions of Georgia and Missouri comprise a measurable or material portion of the entire State's significant contribution to downwind nonattainment. Specifically, OTAG's technical findings and recommendations state 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, we performed State-by-State modeling for Georgia and Missouri as part of the final NO_X SIP Call rulemaking. The results of this modeling show that emissions in both Georgia and Missouri make a significant contribution to nonattainment in other States. Again, our finding of significant contribution was not disturbed by the Court, and the Court stated that the Georgia and Missouri industry petitioners challenging the rule did not challenge this part of the decision. *Michigan* v. *EPA,* 213 F.3d 681–82.

Examining the 2007 Base Case[23] 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. Moreover, and as the Court pointed out, the fine grid portion of each State lies closer to downwind nonattainment areas. *Michigan* v. *EPA,* 213 F.3d at 683. The OTAG 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.

We see no reason to revise the existing determination that sources in the fine grid parts of Georgia and Missouri contribute significantly to nonattainment downwind. The basis for this determination continues to be: (1) The results of EPA's State-by-State modeling; (2) OTAG's fine grid-coarse grid modeling; (3) the relatively high amount of NO_X emissions per square mile in the fine grid portions of each State; and (4) the close locations of the fine grid portions of each State to downwind nonattainment areas compared to the coarse grid part, as described above. 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 this regard, as with the State of Wisconsin described below, we

[22] 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).

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

will look at the impacts of the coarse grid portions of Georgia and Missouri in conjunction with any further analysis on the remaining 15 OTAG States. In addition, apart from our findings relating to the 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.

We are proposing to revise the NO_X budgets for Georgia and Missouri to include only the fine grid portions of these States. The emissions reductions are therefore required from the fine grid portion of the State. For purposes of determining budgets for the fine grid portion, we believe that the OTAG longitude and latitude lines should be used with an adjustment to account for the fact that some counties have a portion of their emissions in both grids (*i.e.,* counties that straddle the line separating fine and coarse grids). 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. That is, counties which straddle the fine grid-coarse grid line or which are completely within the coarse grid are excluded from the budget calculations for Georgia and Missouri in today's proposal. The counties that we are including 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	Effingham	Jefferson	Putnam
Banks	Elbert	Jenkins	Rabun
Barrow	Emanuel	Johnson	Richmond
Bartow	Evans	Jones	Rockdale
Bibb	Fannin	Lamar	Schley
Bleckley	Fayette	Laurens	Screven
Bulloch	Floyd	Lincoln	Spalding
Burke	Forsyth	Lumpkin	Stephens
Butts	Franklin	McDuffie	Talbot
Candler	Fulton	Macon	Taliaferro
Carroll	Gilmer	Madison	Taylor
Catoosa	Glascock	Marion	Towns
Chattahoochee	Gordon	Meriwether	Treutlen
Chattooga	Greene	Monroe	Troup
Cherokee	Gwinnett	Morgan	Twiggs
Clarke	Habersham	Murray	Union
Clayton	Hall	Muscogee	Upson
Cobb	Hancock	Newton	Walker
Columbia	Haralson	Oconee	Walton
Coweta	Harris	Oglethorpe	Warren
Crawford	Hart	Paulding	Washington
Dade	Heard	Peach	White
Dawson	Henry	Pickens	Whitfield
De Kalb	Houston	Pike	Wilkes
Dooly	Jackson	Polk	Wilkinson
Douglas	Jasper	Pulaski	
Missouri:			
Bollinger	Iron	Oregon	St. Francois
Butler	Jefferson	Pemiscot	St. Louis
Cape Girardeau	Lewis	Perry	St. Louis City
Carter	Lincoln	Pike	Scott
Clark	Madison	Ralls	Shannon
Crawford	Marion	Reynolds	Stoddard
Dent	Mississippi	Ripley	Warren
Dunklin	Montgomery	St. Charles	Washington
Franklin	New Madrid	St. Genevieve	Wayne
Gasconade			

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

We are proposing to calculate Alabama's and Michigan's budgets in the same manner as 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 are proposing to revise the NO_X budgets for Alabama and Michigan to reflect reductions only in the fine grid portions of these States. Again, like Georgia and Missouri, we see no reason to disturb the determination that sources in the fine grid contribute significantly to nonattainment downwind. Like Georgia and Missouri, 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 this 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. The counties in Alabama and Michigan that we are including in the calculation of NO_X

budgets for each of these States are listed in Table 2.

TABLE 2.—FINE GRID COUNTIES IN ALABAMA AND MICHIGAN

Alabama:				
Autauga	Colbert	Greene	Macon	St. Clair
Bibb	Coosa	Hale	Madison	Shelby
Blount	Cullman	Jackson	Marion	Sumter
Calhoun	Dallas	Jefferson	Marshall	Talladega
Chambers	De Kalb	Lamar	Morgan	Tallapoosa
Cherokee	Elmore	Lauderdale	Perry	Tuscaloosa
Chilton	Etowah	Lawrence	Pickens	Walker
Clay	Fayette	Lee	Randolph	Winston
Cleburne	Franklin	Limestone	Russell	
Michigan				
Allegan	Eaton	Kalamazoo	Monroe	St. Clair
Barry	Genesee	Kent	Montcalm	St. Joseph
Bay	Gratiot	Lapeer	Muskegon	Sanilac
Berrien	Hillsdale	Lenawee	Newaygo	Shiawassee
Branch	Ingham	Livingston	Oakland	Tuscola
Calhoun	Ionia	Macomb	Oceana	Van Buren
Cass	Isabella	Mecosta	Ottawa	Washtenaw
Clinton	Jackson	Midland	Saginaw	Wayne

Today, we are proposing to revise the budgets for Alabama and Michigan in the SIP Call regulations to reflect only the fine grid portions of those States. As with Georgia and Missouri, the emissions reductions are therefore required from the fine grid portion of the State. We believe this approach is consistent with the reasoning of the Court's March 3, 2000 opinion concerning Georgia and Missouri and is justified as provided above.[24]

E. What Modifications Will be Made to the NO_X Emissions Budgets?

Today, we are proposing a small change in the statewide emissions budgets. We are proposing to calculate the budgets in the same manner as the technical amendments (65 FR 11222, March 2, 2000) for purposes of defining EGUs. In addition, we are proposing a range of possible control levels (82 to 91 percent) for the natural gas-fired lean-burn IC engines. For the other IC engine subcategories (natural gas fired rich burn, diesel, and dual fuel) we are proposing 90 percent control. Because the vast majority of large IC engines are natural gas fired and about two-thirds of these are lean-burn, we are applying the 82 and 91 percent reductions to all large IC engines for the purpose of roughly estimating this portion of the proposed budget. Therefore, we are proposing to revise the statewide emissions budgets to reflect this range of possible control levels. The final budgets will more precisely reflect the final rule's breakdown of control percentage per subcategory.

We are proposing to calculate 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 82 percent and 91 percent, as well as using the definition of EGUs as described above.

Our proposed budgets are shown in Tables 3–6. For States that have submitted Phase I SIPs, Tables 7 and 8 show the incremental difference between Phase I and Phase II budgets. Several States have already submitted SIPs that meet the entire budget. However, other States have submitted only a Phase I SIP. We propose to require those States to supplement their control plans with rules that will meet the proposed Phase II increment.

TABLE 3.—PROPOSED STATE EMISSIONS BUDGETS AND PERCENT REDUCTION (82 PERCENT IC ENGINE CONTROL & PROPOSED EGU DEFINITION)

[Tons/season]

State	Final base	Proposed 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	6,658	-187	-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	84,922	2,173	2
New Jersey	105,489	96,876	8,613	8
New York	255,658	240,322	15,336	6

[24] Pursuant to the court's order lifting the stay of the SIP submission obligation, the 20 States, including Alabama and Michigan, were required to submit SIPs in response to the SIP Call by October 30, 2000. As discussed above, in letters dated April 11, 2000 to State Governors, we provided that the States that remained subject to the SIP Call 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 Alabama and Michigan could choose to submit SIPs that address emissions only in the fine grid portion of the State.

TABLE 3.—PROPOSED STATE EMISSIONS BUDGETS AND PERCENT REDUCTION (82 PERCENT IC ENGINE CONTROL & PROPOSED EGU DEFINITION)—Continued

[Tons/season]

State	Final base	Proposed 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 4.—PROPOSED STATE EMISSIONS BUDGETS AND PERCENT REDUCTION (91 PERCENT IC ENGINE CONTROL & PROPOSED EGU DEFINITION)

[Tons/season]

State	Final base	Proposed 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	6,658	-187	-3
Illinois	368,870	270,493	98,377	27
Indiana	340,654	229,913	110,741	33
Kentucky	237,413	162,242	75,171	32
Maryland	103,476	81,892	21,584	21
Massachusetts	87,095	84,838	2,257 3	
New Jersey	105,489	96,876	8,613	8
New York	255,658	240,285	15,373	6
North Carolina	224,696	164,987	59,709	27
Ohio	373,222	249,241	123,981	33
Pennsylvania	345,203	257,551	87,652	25
Rhode Island	9,463	9,378	85	1
South Carolina	152,805	123,056	29,749	19
Tennessee	256,765	198,015	58,750	23
Virginia	210,786	180,154	30,632	15
West Virginia	176,699	83,822	92,877	53

TABLE 5.—PROPOSED PARTIAL STATE EMISSIONS BUDGETS AND PERCENT REDUCTION (82 PERCENT IC ENGINE CONTROL & PROPOSED EGU DEFINITION)

[Tons/season]

State	Final base	Proposed budget	Tons reduced	Percent reduction
Georgia	209,914	150,656	59,258	28
Missouri	92,697	61,433	31,264	34
Alabama	169,156	119,827	49,329	29
Michigan	245,929	190,908	55,021	22

TABLE 6.—PROPOSED PARTIAL STATE EMISSIONS BUDGETS AND PERCENT REDUCTION (91 PERCENT IC ENGINE CONTROL & PROPOSED EGU DEFINITION)

[Tons/season]

State	Final base	Proposed budget	Tons reduced	Percent reduction
Georgia	209,914	150,246	59,668	28
Missouri	92,697	61,403	31,294	34
Alabama	169,156	119,290	49,866	29
Michigan	245,929	190,860	55,069	22

TABLE 7.—COMPARISON OF PHASE I AND PROPOSED PHASE II STATE NO_X BUDGETS COMPARISON (82 PERCENT IC ENGINE CONTROL)

[Tons/season]

State	Phase I budget	Proposed phase II 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	6,658	0
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	84,922	949
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

TABLE 8.—COMPARISON OF PHASE I AND PROPOSED PHASE II STATE NO_X BUDGETS COMPARISON (91 PERCENT IC ENGINE CONTROL)

[Tons/season]

State	Phase I budget	Proposed phase II budget	Phase II incremental difference
Alabama	124,795	119,290	5,505
Connecticut	42,891	42,850	41
Delaware	23,522	22,862	660
District of Columbia	6,658	6,658	0
Illinois	278,146	270,493	7,653
Indiana	234,625	229,913	4,712
Kentucky	165,075	162,242	2,833
Maryland	82,727	81,892	835
Massachusetts	85,871	84,838	1,033
Michigan	191,941	190,860	1,081
New Jersey	95,882	96,876	−994
New York	241,981	240,285	1,696
North Carolina	171,332	164,987	6,345
Ohio	252,282	249,241	3,041
Pennsylvania	268,158	257,551	10,607
Rhode Island	9,570	9,378	192
South Carolina	127,756	123,056	4,700
Tennessee	201,163	198,015	3,148
Virginia	186,689	180,154	6,535
West Virginia	85,045	83,822	1,223

F. How Will the Compliance Supplement Pools Be Handled?

The compliance supplement pool is a pool of allowances that can be used in the beginning of the program to provide affected sources additional compliance flexibility in order to address concerns raised by commenters on the SIP Call proposal regarding electric reliability. In the SIP Call Rule, the compliance supplement pool may be used in the years 2003 and 2004 (see 63 FR 57428–57430, October 27, 1998, for further discussion of the compliance supplement pool). In *Michigan*, the Court of Appeals for the District of Columbia Circuit ruled that May 31, 2004, rather than May 1, 2003 is the date by which sources must install controls to comply with the SIP Call. Consequently, to be consistent with the original 2-year window specified in the SIP Call in which we allowed the compliance supplement pool allowances to be used, we are extending the time that allowances from the compliance supplement pool can be used from September 30, 2004 to September 30, 2005. We are also proposing to include compliance supplement pools 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 compliance supplement pool allowances may be distributed under the NO_X SIP call *see* 63 FR 57429.) The allowances from Georgia's and Missouri's compliance supplement pools may be used to account for emissions during the first 2 years' ozone seasons that sources in those States are required to comply.

We are not proposing to change the individual State compliance supplement pool 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 compliance supplement pools to reflect the State budget changes made in this action would result in minimal impacts on the size of any State's compliance supplement pool. Therefore, we have decided to maintain the compliance supplement pools at the levels determined in the March 2, 2000 technical amendment (with the exception of Alabama, Georgia, Michigan, Missouri, and Wisconsin).

Since the proposed required reductions in Georgia, Missouri, Alabama, and Michigan are less than the required reductions of the September 24, 1998 NO_X SIP Call reflecting full State emissions budgets, we propose to make corresponding decreases to the compliance supplement pools for the portion of each State that is still subject to the SIP Call. We propose to calculate the partial-State compliance supplement pools by prorating the size of the full-State compliance pool by the ratio of the reductions that we are proposing for the partial-State to the reductions that we required in the March 2, 2000 Technical Amendment (65 FR 11222). However, to be consistent with the way the compliance supplement pool was calculated in the other States, we are assuming a 90 percent reduction from IC engines for purposes of calculating the compliance supplement pool. In addition, since Wisconsin is not being required to make reductions at this time, Wisconsin is no longer receiving a share of the compliance supplement pool. (Wisconsin's original compliance supplement pool was 6,920 tons.) For these reasons, the total compliance supplement pool is now less than 200,000 tons. The revised compliance supplement pools for Georgia, Missouri, Alabama, and Michigan are shown in Table 9.

TABLE 9.—COMPLIANCE SUPPLEMENT POOLS (CSP)

	Full state tons reduced (from March 2, 2000 FR)	Partial state tons reduced with 90% IC engine control	Full state CSP	Partial state CSP reduced with 90% IC engine control
GA	63,582	57,623	11,440	10,728
MO	62,242	31,291	11,199	5630
AL	64,954	49,806	11,687	8962
MI	63,118	55,064	11,356	9907

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 Ozone Transport Commission (OTC) NO_X Budget program. It also reallocated the three States' compliance supplement pools.

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 proposed in today's action would 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 State's 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 proposed 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 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 SIP Call, transportation conformity budgets must reflect the mobile source controls assumed in the 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 proposing to include only partial State budgets for Alabama, Georgia, Michigan, and Missouri. Therefore, we are offering to administer a trading program for the NO_X SIP Call region that, for these four States, includes only the portion of the States proposed for inclusion 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 would be allowed to participate in trading with sources in States which are subject to either the NO_X SIP Call or the Section 126 rulemaking.

J. What SIP Submittal Dates Are We Proposing?

In today's action, we are proposing a range of due dates for States to submit SIPs meeting the Phase II NO_X budgets and the partial State budgets for Georgia and Missouri. We believe that the appropriate timeframe to consider for SIP submittal is 6 months to 1 year from final promulgation of this rulemaking but no later than April 1, 2003, and we request comment on which date within this timeframe is appropriate. We believe that a deadline within this range 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 proposed in this action. Please see section K, below, for a discussion of the compliance dates.

In establishing the end of the range, *i.e.,* April 1, 2003, we considered the fact that the original NO_X SIP Call Rule allowed 12 months from the date of promulgation for SIPs to be due. We are hopeful that we will finalize this rulemaking in Spring 2002. The purpose of having an end date to the range is to ensure that sources can comply by the dates discussed below, which will ensure that the reductions necessary to minimize ozone transport occur expeditiously.

We believe that a SIP submittal due date within the proposed range would give States adequate time to adopt rules and give sources adequate time to install control equipment needed to comply.

K. What Compliance Dates Are We Proposing?

There are two primary issues that need to be considered when determining a reasonable date by which EGUs covered by any Phase II SIPs or by SIPs in Georgia and Missouri, can install controls to achieve the emissions reductions required:

(1) How long does it take to complete the design, construction, and testing of the controls on large boilers used to generate electricity?

(2) Does the amount of time that EGUs are taken off-line to install controls adversely affect the reliability of the electric power system? In other words, does installation of controls reduce the amount of available generation to the point where no power can be supplied to certain users for a period of time?

We believe control equipment can generally be applied in an expeditious manner. For example, controls on IC engines may be installed in less than 1 year. States that choose to control large EGUs, however, may experience longer timeframes for installation of post-combustion controls. For this reason, we analyzed the timeframe required to install controls on large EGUs as part of our decision on the appropriate compliance date to set.

In an effort to remain consistent with the August 30, 2000 Court of Appeals' decision regarding the compliance date for Phase I of the NO_X SIP Call, we are proposing a compliance date of May 31, 2004 for Phase II sources. We are proposing a May 1, 2005 compliance date for affected sources in Georgia and Missouri. We request comment on the feasibility of these compliance dates.

Given a Phase II SIP submittal date as late as April 1, 2003, owners and operators of affected units subject to State control requirements would have about 13 months, and affected units in Georgia and Missouri would have about 25 months to install the necessary controls.

The discussion below supports a Phase II SIP submittal date as late as April 1, 2003 for the 19 States and District of Columbia, as well as for Georgia and Missouri. Of course, adopting and submitting the SIP earlier would provide additional time for the installation of controls.

1. What Is the Technical Feasibility of the Compliance Dates?

Under Section 126, we issued a final rule determining that sources in nine jurisdictions (Delaware, District of Columbia, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia) and portions of four other jurisdictions (Indiana, Kentucky, Michigan, and New York) named in the NO_X SIP Call significantly contribute to nonattainment in one or more of the petitioning States. As finalized by EPA, that rule directly regulated sources within the 13 States and required compliance by May 1, 2003 (64 FR 28250, May 25, 1999 and 65 FR 2674, January 18, 2000). On August 24, 2001, the D.C. Circuit issued an order in the *Appalachian Power-126 Case,* tolling the date for implementing the controls required under the Section 126 Rule. Our analysis of the time needed to comply with the Phase II rulemaking is still applicable as long as sources are required to comply with the Section 126 requirements by May 31, 2004. In addition, as part of the OTC NO_X Budget Program, the remaining Northeast States covered in today's action (Connecticut, Massachusetts, New York and Rhode Island) have submitted SIPs, which we have approved, to comply by May 1, 2003 with the NO_X SIP Call.

We examined the time needed to install the post-combustion controls (SCR and SNCR) on large boilers used to generate electricity because they represent the most time-consuming NO_X control retrofits. In this feasibility analysis, we looked at the retrofits we projected were needed for affected units in Georgia and Missouri and Phase II units in the remaining States to comply with the NO_X SIP Call. These remaining States include: Alabama, Georgia, Illinois, Missouri, South Carolina, and Tennessee and portions of Indiana, Kentucky, and Michigan.

We believe that if States (other than Georgia and Missouri) submit SIPs by April of 2003, there is still sufficient time for sources to install the necessary controls by May 31, 2004. To determine the amount of time involved, we analyzed which sources would reasonably be expected to be subject to the Phase II rule. While States may meet the requirements of the SIP Call by requiring reductions from any sources that are available, most States, as a means of compliance with Phase I of the SIP Call, are choosing to require reductions from the same group of sources that we considered in determining the budgets. Therefore, we believe it is reasonable to assume that States will also regulate, as part of their Phase II compliance strategy, the same sources that we used to develop the Phase II budgets.

Our analysis showed that under Phase II, and assuming the multi-state trading program, three small coal-burning units would elect to install SNCR control technology (September 2000 Feasibility memorandum, docket # A–96–56, item # XII–K–46). We projected that most of the other units would not need to install post-combustion controls because they were either already under an emission rate of 0.15 lbs/mmbtu, or they were infrequently operated sources that would find it more economical to purchase allowances than to install post-combustion control equipment. Although installation of SNCR may in some cases be time-consuming, we believe that these sources will be able to comply by the May 31, 2004 compliance date for several reasons. First, we are setting emission budgets for the year 2004 based on a 5-month ozone season. Because States are required to submit

SIPs that demonstrate compliance with only a 4-month period in 2004, their emission budgets will be larger than needed to meet an emission cap of 0.15 lbs/mmbtu in 2004. Therefore, States will have more than their sources need to achieve the 0.15 lb/mmBtu level in 2004. The States will have flexibility to allocate these allowances recognizing that some sources—such as the three sources noted above—may need extra time to comply.

Furthermore, even though we projected that it would take 19 months to install SNCR, the actual installation process is projected to take only 8 months. The majority of the 19-month installation is related to obtaining a construction permit (9 months). Because sources should have a strong indication of whether they are going to be regulated under a State's Phase II rulemaking before the rulemaking is complete, sources could begin this process before a State's rule was finalized. In addition, because only a small number of sources are involved, States may have opportunities to expedite their construction permitting process.

However, for sources in the fine-grid portions of Georgia and Missouri, we propose a May 1, 2005 compliance date. This date will give them 25 months to install necessary controls if States submit SIPs by April 1, 2003. In Missouri, at most three installations of SNCR are projected, or two installations of SCR and one installation of SNCR. In Georgia, installations would be not more than seven SNCRs, or two SCRs and one SNCR. In our analysis, we projected that two SCRs and one SNCR could be installed in less than 25 months and that seven SNCR's could be installed in 23 months (September 2000 Feasibility memorandum, docket # A–96–56, item # XII–K–46). Furthermore, sources in both Georgia and Missouri are already installing some post-combustion controls to come into compliance with ozone nonattainment SIPs. In addition, because much of the work that will be done in Georgia and Missouri will be done after post-combustion controls have been installed in many other States, sources in these States will be able to take advantage of expertise gained in these other installations to reduce the amount of time required to install the controls. For these reasons, we believe the May 1, 2005 implementation date is feasible for Georgia and Missouri.

We are also aware that States could choose to utilize the compliance supplement pool to assist units that demonstrate a need for a longer compliance timeframe, particularly, the small number of units in Phase II States that might decide to install post-combustion controls. Furthermore, sources could choose to use the trading system to help meet these compliance dates, either by purchasing credits from other parties or by banking emissions at other units they control and using those credits as needed.

2. How Will This Affect Electric Reliability?

Concerns about electric reliability arise whenever units are down, particularly during periods of peak demand. Since units may need to be off-line for longer periods of time to install emission controls than they normally would be if the units were just being shut down to perform other scheduled maintenance, the installation of emission controls may increase concerns about reliability. The potential impact varies depending on the number of units that have to install controls, the additional time that these units have to be taken off-line, and the number of units that are off-line at one time.

We do not anticipate that the installation of NO_X controls, including SCR, will threaten the reliability of the power supply, even during the summer months when the demand for electricity is highest. Since SCR is a post-combustion control device that is not part of the boiler, most of the SCR retrofit can be constructed while the boiler is operating to supply electricity. The boiler needs to be turned off only when the SCR is actually connected to the ducts leaving the boiler. Owners and operators of electric power plants normally schedule connections of these controls during off-peak periods (usually spring or fall), when they already plan to shut down the unit to perform other scheduled maintenance.

The EPA and industry groups examined the reliability of the power supply in the context of a May 2003 compliance date for the entire NO_X SIP Call region. Based on these studies, we concluded that installation of NO_X controls for the entire NO_X SIP Call region (including Phase I and Phase II affected units and affected units in Georgia and Missouri) by May 1, 2003 will not threaten the reliability of the electric power supply. Therefore, we conclude that providing additional time (an additional year and 1 month) for the installation of controls on some of the affected units further ensures that the reliability of the electric power supply will not be threatened by this rule.[25]

a. Reliability in Georgia and Missouri. In the final NO_X SIP Call and the final Section 126 Rule, we included the compliance supplement pool to address commenters' concerns regarding electricity reliability. Therefore, to remain consistent with the intent of the original NO_X SIP Call, we are proposing to include compliance supplement pools 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 compliance supplement pool allowances may be distributed under the NO_X SIP Call See 63 FR 57429.) The allowances from the pools may be used to account for emissions during the first two ozone seasons that Georgia and Missouri are required to comply, which under this proposal would be in 2005 and 2006. The size of their compliance supplement pools have been adjusted to account for the proposed change in geographic coverage. See section II.F. of today's action for a complete discussion of how the size of Georgia and Missouri's compliance supplement pools were calculated.

With a later compliance date (May 1, 2005 as proposed) than the rest of the SIP Call region and the Section 126 region, we believe that concerns about the risk to electric reliability due to the installation of controls in Georgia and Missouri are not justified. Sources in both Georgia and Missouri are expected to install some NO_X controls before May 1, 2005 as part of the States' ozone attainment plans. Furthermore, by May 1, 2005, we expect there to be an active NO_X allowance market on which sources in Georgia and Missouri could rely should they experience an unexpected delay in installing controls.

L. What Are We Proposing for Wisconsin?

In the NO_X SIP Call litigation, 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

[25] We assumed that sources in States affected under the OTC MOU and the Section 126 action will install controls by May 1, 2003, but sources in the other States affected by the SIP Call (Alabama, Illinois, South Carolina, Tennessee and portions of Indiana, Kentucky, and Michigan) will have until May 31, 2004 to install controls. In this action, we are proposing that Georgia and Missouri will have until May 1, 2005 to install controls. Sources that will not have to complete installation of controls until May 31, 2004 represent approximately 40 percent of the generation capacity in the SIP Call Region.

nonattainment in * * * any other State'' in order to be included in the challenged 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,*'' 213 F.3d at 361 (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* v. *EPA,* 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. Since we do not currently have the modeling necessary to make such a proposal, we intend to exclude 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.

We are not, however, proposing to determine 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. In the final NO_X SIP Call, we took no action on whether emissions from sources in 15 States [26] in the OTAG region do or do not contribute significantly to downwind nonattainment, or interfere with maintenance downwind, under either the 1-hour or the 8-hour ozone NAAQS. We will continue to review available information on the downwind impacts of these States. We plan to look at the impacts of Wisconsin in conjunction with any further analysis on the remaining 15 States. To date, we have stayed the 8-hour basis of the SIP Call Rule (65 FR 56245, September 18, 2000) and the Court has stayed consideration of the 8-hour basis of the SIP Call Rule. Today's action to exclude Wisconsin from the 1-hour basis of the SIP Call does not address whether Wisconsin should remain subject to the 8-hour basis of the SIP Call. We will address that issue at the time it lifts the stay as it applies to Wisconsin.

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

As noted above, the revisions to the NO_X SIP Call proposed in today's action respond to the Court's decision in *Michigan* v. *EPA.* The Court's decision and today's proposal concern issues arising under only the 1-hour ozone NAAQS, and not the 8-hour NAAQS. Accordingly, none of the actions proposed today—the definition of EGU and the control requirements for IC engines, and implications for the State budgets; the SIP submission dates; the revised emissions budgets for Alabama, Georgia, Michigan, and Missouri; and the exclusion of Wisconsin—if finalized, would have any effect on any requirements of the SIP Call on States under the 8-hour NAAQS. Because of the litigation concerning the 8-hour ozone NAAQS, we have stayed all of the requirements of the SIP Call under the 8-hour NAAQS, ranging from the SIP submission dates to the control requirements (65 FR 56245, September 18, 2000). After the litigation concerning the 8-hour NAAQS is resolved, we will determine whether to proceed with the 8-hour requirements under the SIP Call.

III. What Are the Administrative Requirements?

A. Executive Order 12866: Regulatory Impact Analysis

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 proposed action, which responds to the court decisions in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000) (NO_X SIP Call); *Appalachian Power* v. *EPA,* 249 F.3d 1032 (D.C. Cir. 2001) (Section 126 Rule), and *Appalachian Power* v. *EPA,* 251 F.3d 1026 (D.C. 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.

Since 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 A–96–56)] 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, 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), an analysis prepared for the IC engine portion of this action. 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. This document is available for public inspection in Docket A–96–56 which is listed in the **ADDRESSES** section of this preamble.

B. Executive Order 12898: Environmental Justice

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

[26] Arkansas, Florida, Iowa, Kansas, Louisiana, Maine, Minnesota, Mississippi, North Dakota, Nebraska, New Hampshire, Oklahoma, South Dakota, Texas, Vermont.

findings were presented in the RIA for each of these rules. Today's action does not affect these analyses.

C. Executive Order 13045: Protection of Children From Environmental Health Risks 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.

D. 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 proposed 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 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 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 D.C. 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 (D.C. Cir. 2000) (NO_X SIP Call). Today, EPA is proposing 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 (D.C. Cir. 2001) (NO_X SIP Call Technical Amendments).

With respect to the proposed action concerning the definition of EGU and the level of control for internal combustion engines, the proposed action revising the emission budgets for Georgia, Missouri, Alabama, and Michigan, and the SIP submission and source compliance dates, EPA's proposal 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 SIP Call Rule, which remains in place for 19 States (including Alabama and Michigan) and the District of Columbia. Moreover, no aspect of the proposed 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 SIP Call Rule to choose the control requirements necessary to address the transported emissions identified by EPA in the SIP Call.

As provided in the final action promulgating the SIP Call and the Technical Amendments, the SIP Call 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 (D.C. 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).

E. 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 proposed 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.

In the spirit of Executive Order 13175, and consistent with EPA policy to promote communications between EPA and tribal governments, EPA specifically solicits additional comment on this proposed rule from tribal officials.

F. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This summary of the energy impact analysis report 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 EGUs that do not participate in the Acid Rain Trading Program and reciprocating internal combustion engines (RICE) 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 RICE) in the fine grid portions of Georgia and Missouri. In addition, this analysis does not consider impacts on sources in the coarse grid portions of Michigan and Alabama since these sources are not covered in the Phase II rulemaking. The Agency 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 its analysis, the Agency identified three relevant energy effects that occur during normal operation of these devices: increased energy demands required by 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.[26] With respect to energy sources, the application of LEC technology to natural gas-driven internal combustion (IC) engines amounts to a savings of about 4,000 million British thermal units (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 all 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 proposed 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.

G. 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 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.

H. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis for any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

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

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

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 proposed action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This proposed action will not impose any requirements on small entities. This action responds to the court decisions in *Michigan* v. *EPA*, 213 F.3d 663, *Appalachian Power* v. *EPA*, 249 F.3d 1032 (D.C. Cir. 2001), and *Appalachian Power* v. *EPA*, 251 F.3d 1026 (D.C. 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.

I. 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.

J. National Technology Transfer and Advancement Act

In addition, the National Technology Transfer and Advancement Act of 1997 does not apply because today's proposed 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 proposed 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.

The EPA is not proposing rule language in today's document. In the final rulemaking action in this proceeding, EPA will adopt rule language implementing the final action.

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 52

Air pollution control, Ozone, Reporting and recordkeeping requirements.

40 CFR Part 96

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

40 CFR Part 97

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

Dated: February 12, 2002.

Christine T. Whitman,

Administrator.

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