6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51 and 96

[FRL-XXXX-X]

Rulemaking for Purposes of Reducing Interstate Ozone Transport: Response to March 3, 2000 Decision of the United States Court of Appeals for the District of Columbia Circuit

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In today's action, EPA is proposing to amend a final rule it issued under section 110 of the Clean Air Act (CAA) related to interstate transport of nitrogen oxides (NOx), one of the main precursors to ground-level ozone. The EPA is 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 NOx State Implementation Plan Call (NOx SIP Call), but remanded four narrow issues to EPA for further rulemaking action.

In the final NOx SIP Call, EPA found that emissions of NOx 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). The EPA established statewide NOx emissions

budgets for the affected States. Today's action addresses the issues remanded by the Court for notice-and-comment rulemaking and proposes related amendments.

DATES: Comments must be postmarked, faxed, or e-mailed by [INSERT 45 DAYS FROM PUBLICATION]. A public hearing will be held in Washington, DC on February 13, 2001 beginning at 9:00 am.

ADDRESSES: Comments may be submitted to the Air and Radiation Docket and Information Center (6102), Attention: Docket No. A-96-56, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave., NW, Washington, DC 20460, telephone (202) 260-7548. The EPA encourages 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 will be held at the EPA Auditorium at 401 M Street, SW, Washington D.C., 20460.

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 8:00 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: Questions concerning today's action should be addressed to Kimber Scavo, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, Research Triangle Park, NC, 27711, telephone (919) 541-3354, e-mail at scavo.kimber@epa.gov.

SUPPLEMENTARY INFORMATION:

Today’s action addresses the issues remanded by the Court for notice-and-comment rulemaking: (i) the definition of electric generating units (EGUs) as it relates to cogeneration units, (ii) the control level for stationary internal combustion engines, (iii) the revised emissions budgets for Georgia and Missouri; (iv) a range of dates (128 days through 1 year from final promulgation of this rulemaking but no later than April 1, 2002) by which States would be required to submit a SIP to address the emissions reductions reflected by EPA’s final action on the cogeneration unit and internal combustion engine issues and for Georgia and Missouri to submit full SIPs meeting the SIP Call; (v) the proposed changes to the statewide NOx budgets; and (vi) the exclusion of Wisconsin from the NOx SIP Call requirements. In addition, today’s action addresses a related issue: revised emissions budgets for Alabama and Michigan consistent with the Court’s decision.

Today’s action also provides notice of how EPA’s proposed revision to the definition of EGUs as it relates to cogeneration units would affect EPA’s proposed re-allocation of the SIP Call budgets among three States – Connecticut, Massachusetts, and Rhode Island – in accordance with a February 1999 Memorandum of Understanding (64 FR 50036, 49987; September 15, 1999).

Finally, today’s action proposes revisions to the NOx emissions budgets in the final NOx SIP Call Rule to reflect the changes EPA is proposing in response to the Court’s remand.

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

Public Hearing

A public hearing will be held in Washington, DC on February 13, 2001 beginning at 9:00 am. The hearing will be held at the EPA Auditorium at 401 M Street, SW, Washington

D.C., 20460. The metro stop is Waterfront, which is on the green line. If you wish to attend the hearing or wish to present oral testimony, you should notify, on or before February 6, 2001, Ms. JoAnn Allman, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, MD-15, 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 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 Air and Radiation Docket and Information Center at the above address listed for inspection of documents.

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. Electronic comments on this proposed rule may be filed online at many Federal Depository Libraries.

Availability of Related Information

The official record for the NOx SIP Call rulemaking, as well as the public version of the record, has been established under docket number A-96-56 (including comments and data submitted electronically as described below). The EPA has added new sections to that docket for purposes of today's proposed rulemaking. The public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as CBI, is available for inspection from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays. The rulemaking record is 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. Paperwork Reduction Act

I. Background

A. September 24, 1998 NOx SIP Call

On September 24, 1998 (63 FR 57356, October 27, 1998), EPA took final action to prohibit specified amounts of emissions of one of the main precursors of ground-level ozone, NOx, 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, EPA found that sources in 23 States emit NOx in amounts that significantly contribute to nonattainment of the 1-hour ozone NAAQS. The EPA set forth requirements for each of the affected upwind States to submit SIP revisions prohibiting those amounts of NOx emissions which significantly contribute to downwind air quality problems. The EPA established statewide NOx 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 NOx. States have the flexibility to adopt the appropriate mix of controls for their State to meet the NOx emissions reduction requirements of the SIP Call. A number of parties, including certain States as well as industry and labor groups, challenged EPA’s NOx SIP Call Rule.

Independently, EPA also found that sources and emitting activities in 23 States emit NOx in amounts that significantly contribute to nonattainment of the 8-hour ozone NAAQS. However, EPA has indefinitely stayed the NOx SIP Call as it applies for the purposes of the 8-hour NAAQS (65 FR 56245, September 18, 2000).

B. Court Decisions

1. 8-Hour NAAQS and Stay of the 8-hour Portion of the SIP Call

On May 14, 1999, the D.C. Circuit issued an opinion questioning the constitutionality of the CAA as applied by EPA in its 1997 revision of the ozone and particulate matter NAAQS. See American Trucking Ass’ns v. EPA, 175 F.3d 1027 (D.C. Cir., 1999). The Court’s ruling curtailed EPA’s 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 EPA’s rehearing request. American Trucking Ass’ns v. EPA, 194 F.3d 4 (D.C. Cir. 1999). On January 27, 2000, the Administration filed a petition of certiorari with the Supreme Court seeking review of this opinion. Several of the parties who challenged the NAAQS filed conditional cross-petitions for certiorari on the issue of whether the CAA precludes the consideration of costs in establishing NAAQS. In May, the Supreme Court granted EPA's petition and the petitioners' cross-petitions. The ongoing litigation continues to create uncertainty with respect to EPA's ability to rely upon the 8-hour ozone standards as an alternative basis for the NOx SIP Call at this time.

As a result, EPA stayed the 8-hour basis of the final NOx SIP Call (65 FR 56245, September 18, 2000). The EPA's belief is that EPA should not continue implementation efforts under section 110 with respect to the 8-hour standard that could be construed as inconsistent with the Court's ruling. Therefore, EPA stayed indefinitely the findings of significant contribution based on the 8-hour standard, pending further developments in the NAAQS litigation. Because the rule was based independently on the 1-hour standards, a stay of the findings based on the 8-hour standards would have no effect on the remedy required by the 1998 NOx SIP Call. The stay does not affect EPA's findings based on the 1-hour standards.

2. Stay of SIP Submittal Schedule for the NOx SIP Call

The September 24, 1998 NOx SIP Call required States to submit SIP revisions by September 30, 1999. State Petitioners challenging the NOx 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).

3. NOx SIP Call Court Decision

On March 3, 2000, the D.C. Circuit issued its decision on the NOx SIP Call, ruling in favor of EPA on all the major 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 NOx SIP Call, and not the 8-hour basis. The requirements of the NOx 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 NOx emissions reduction requirements, are fully and independently supported by EPA's 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 favor of EPA on the following claims:

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

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

(3) EPA did not unlawfully override past precedent

regarding "significant" contribution;

(4) EPA's consideration of the cost of NOx reduction as part of the determination of significant contribution is consistent with the statute and judicial precedent;

(1) EPA's scheme of uniform emissions reduction requirements is reasonable;

(6) CAA § 110(a)(2)(D)(i)(I) as construed by EPA does not violate the nondelegation doctrine;

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

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

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

However, the Court ruled against EPA on four narrow 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 EPA failed to provide adequate notice of the change in the definition of EGU as applied to cogeneration units; and

(4) held that EPA 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.

Today's proposal addresses the definition of EGUs and the control level for large stationary internal combustion engines, as well as issues under the 1-hour ozone NAAQS regarding Wisconsin, Georgia, and Missouri. In addition, EPA is proposing to limit the emissions budgets for Alabama and Michigan to the fine grid portion of each State, similar to the proposal for Georgia and Missouri. Because EPA has stayed the findings based on the 8-hour NAAQS under the NOx SIP Call, EPA is not addressing NOx SIP Call issues related to the 8-hour NAAQS.

4. Lifting the Stay of the 1-Hour SIP Submission Schedule

On April 11, 2000, EPA filed a motion with the Court to lift the stay of the SIP submission date. The EPA requested that the Court lift the stay as of April 27, 2000. The EPA recognized, however, that at the time the stay was issued, States had approximately 4 months (128 days) remaining to submit SIPs. Therefore, EPA's motion to lift the stay indicated that EPA 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 NOx 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, EPA has 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, EPA identified an adjusted Phase I NOx budget for each State for which the SIP Call applies.

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

In its motion to lift the stay, EPA 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 EPA's motion to lift the stay. The 19 States are: Alabama,

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

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 NOx SIP Call, these 19 States and the District of Columbia may choose to submit SIPs that cover all of the NOx SIP Call requirements except for a small part of the EGU portion and large internal combustion engine portion of the budget. The EPA refers to these partial plans that address the portion of the rule unaffected by the Court's remand as "Phase I."[2]

Today's action sets forth EPA's proposal for the second phase or Phase II by addressing the remanded portion of the definition of EGUs, the control level for large internal combustion engines, and the emissions budgets for Georgia and Missouri. In addition, EPA proposes to modify the budgets for Alabama and Michigan based on inclusion of only a portion of those States. 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 Phase II submittal is a relatively small supplement to the SIPs that would be

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

submitted to meet Phase I, 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.1 and II.J.3. The proposed changes to the State's emissions budgets are discussed in section II.E.

5. Compliance Date Court Order

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 NOx 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 NOx SIP Call would have 1,309 days for implementing the SIP as provided in the original NOx SIP Call. This action was in response to a motion filed by the industry/labor petitioners.

C. Relationship to Section 126 Petitions

The EPA has also addressed interstate NOx transport in a January 18, 2000 final rule (January 18, 2000 Rule) that responds to petitions submitted by eight Northeast States under section 126 of the CAA (65 FR 2674). In this rule, EPA 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 States with sources affected by the January 18, 2000 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 establishes Federal NOx emissions limits that sources must meet by May 1, 2003. The EPA promulgated a NOx 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 NOx SIP Call.

The January 18, 2000 Rule includes a provision to coordinate the section 126 rule with State actions under the NOx SIP Call. This provision automatically withdraws the section 126 findings and control requirements for sources in a State if the State submits, and EPA gives final approval to, a SIP revision meeting the full NOx SIP Call requirements, including the originally promulgated May 1,

[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 EPA is proposing for the NOx SIP Call in today's action.

2003 compliance deadline (40 C.F.R. 52.34(i)). The EPA has already received NOx SIPs from several States that require the full amount of reductions by May 1, 2003.[5] While the court has changed the NOx SIP Call compliance deadline to May 31, 2004, EPA 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 NOx SIP Call may be addressed through future rulemaking.

II. Proposal

In this action, EPA is soliciting comment on only the specific changes the Agency is proposing in response to the Court’s rulings. The EPA is not reopening the remainder of the final NOx SIP Call for public comment and reconsideration. Specifically, EPA is soliciting comment on the following:

(1) certain aspects of the definitions of EGU and non-EGU. The EPA is not proposing to change the manner in which the budgets are calculated for EGUs and non-EGU boilers

[5]To date, EPA has received NOx SIPs from Connecticut, Rhode Island, Massachusetts, New Jersey, New York, and Maryland.

and turbines from the final NOx SIP Call and the technical amendments. The EPA is addressing the remanded issue concerning the definition of EGU as applied to cogeneration units by proposing to retain the basic EGU definition used in the September 24, 1998 NOx SIP Call Rule. In addition, EPA is proposing minor, technical changes to the EGU definition to make it consistent with the definition of EGU used in the January 18, 2000 section 126 final 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. Today's proposal concerning these definitions does not affect the budgets established under the final NOx SIP Call and the technical amendments.

(2) the control level assumed for large stationary internal combustion engines. The EPA is 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.

(4) 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 SIP call: 128 days through 1 year from final promulgation of this rulemaking but no later than April 1, 2002.

(5) whether the proposed changes to the statewide NOx budgets 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).

A. Definitions of EGU and non-EGU

Under the NOx 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. The EPA determined that reductions by large EGUs to 0.15 lb NOx/mmBtu and by large non-EGUs to 60 percent of uncontrolled emissions are highly cost effective. In developing the States' budgets, EPA applied definitions of EGU and non-EGU and determined which sources were large EGUs or large non-EGUs.

In its March 3, 2000 decision, the D.C. Circuit upheld this approach, but determined that EPA did not provide sufficient notice and opportunity to comment for one aspect of EPA's definition of EGU and remanded the rulemaking to EPA 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). State of Michigan v. EPA, 213 F.3d at 691-92. According to the Court, "two months after the promulgation of the [NOx 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 State of Michigan).

The petitioner argued that, under the NOx SIP Call, EPA 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." State of 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 EPA for further consideration of this issue.

The EPA discusses below the historical definition of utility unit, the definition of EGU in the NOx 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, EPA has sought to distinguish between utilities (regulated monopolies in the business of producing and selling electricity) and non-utilities. In making this distinction, EPA 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, EPA believes that these criteria no longer distinguish between units in the business of producing and selling electricity (i.e., EGUs) and non-EGUs.

1. Historical Definition of Utility Unit

In prior regulatory programs, EPA has 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.

The EPA explained that it was 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. The EPA 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. The EPA 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.

The EPA’s approach in subpart Da reflected the fact that, since before the 1970s and into the 1980s, 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 already subject to the requirements for regulation of hazardous air pollutants under section 112, while cogeneration units included in that definition will become subject to regulation under section 112 only to the extent that the required study is conducted and the necessary finding is made. (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).

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. NOx SIP Call Definition of EGU

In the NOx SIP Call rulemaking, EPA defined EGU by applying to all fossil fuel-fired units the methodology described in detail below. The EPA 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), EPA 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 EPA classified the unit as a large or small EGU or a large or small non-EGU.

Specifically, EPA noted in a December 24, 1998 supplemental action that the NOx SIP Call used the following methodology[6] for classifying all units (including cogeneration units) in the States subject to the NOx SIP Call as EGUs or non-EGUs, (63 FR 71223, December 24, 1998). The EPA applied this methodology to cogeneration units and not the one-third potential electrical output capacity/25MWe sales criteria of the “cogeneration exclusion.” <u>See</u> <u>id.</u>

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[6]The numbering of the methodologies is added for the convenience of the reader.

(a)(i) For units that commenced operation before January 1, 1996, EPA 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, EPA did not define the term "electricity for sale under firm contract to the electric grid."[7]

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

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

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[7]For purposes of the January 18, 2000 section 126 final rule, EPA 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, EPA proposes 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 <u>Glossary of Electric Utility Terms</u>, Edison Electric Institute, Publication No. 70-40 (definition of "firm" power). Generally, capacity "under firm contract to the electricity grid" is included on 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).

(a)(iv) below.

(iv) For units that commenced operation on or after January 1, 1996, EPA 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, EPA did not define the term “usable energy”.[8]

(b)(i) For a unit classified (under paragraph (a)(i) or (a)(iii) above) as an EGU, EPA 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

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[8]For purposes of the January 18, 2000 section 126 final rule, EPA used the more familiar term “potential electrical output capacity,” rather than the term “usable energy,” and adopted 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, EPA proposes 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).

capacity equal to or less than 25 MWe is a small EGU. In the December 24, 1998 supplemental action, EPA did not expressly define the term "nameplate capacity."[9]

(ii) For a unit classified (under paragraph (a)(ii) or (a)(iv) above) as a non-EGU, EPA 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, EPA did not expressly define the term "maximum design heat input".[10]

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[9] In the part 96 model rule in the NOx SIP Call (63 FR 57356, 57514-38) and subsequently for purposes of the January 18, 2000 section 126 final rule (65 FR 2729 and 2731), EPA 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, EPA proposes 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).

[10] In the part 96 model rule in the NOx SIP Call (63 FR 57516) and subsequently for purposes of the January 18, 2000 section 126 final rule (65 FR 2729), EPA 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

As stated previously, EPA 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 with regard to non-EGUs. The EPA did not use, for cogeneration units, the one-third potential electrical output capacity/25 MWe sales criteria in the “cogeneration exclusion.” The petitioners in State of Michigan challenged the failure to apply the one-third potential electrical output capacity/25 MWe sales criteria to determine whether cogeneration units are EGUs or non-EGUs, and the Court, agreeing that EPA had not provided sufficient notice and opportunity for comment on the lack of such application, remanded the rulemaking to EPA for further consideration.

3. The “Cogeneration Exclusion” Criteria and Minor Revisions to NOx SIP Call Definition of EGU

In today’s rulemaking, EPA is addressing three aspects of the EGU definition. First, EPA is proposing not to apply to cogeneration units the one-third potential electrical output/25 MWe sales criteria of the “cogeneration exclusion”

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steady state basis, as determined by the physical design and physical characteristics of the unit.” As discussed below, EPA proposes to adopt in today’s proposed rule the same definition used in the January 18, 2000 section 126 final rule.

in classifying the units as EGUs or non-EGUs. Under today's proposal, EPA would apply to all units, including cogeneration units, the basic approach used in the NOx SIP Call Rule (and described in the December 24, 1998 supplemental action (63 FR 71233)) for such classification. Further, EPA is proposing to change the categorization of units under the NOx SIP Call definition of EGU (set forth in paragraph (a) above of preamble section II.A.2) as units commencing operation before January 1, 1996 or units commencing operation on or after January 1, 1996. Under today's proposal, EPA 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. The EPA is 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 final rule. As noted above, these changes to conform to the January 18, 2000 section 126 final rule do not affect the budgets that were established under the final NOx SIP Call and the technical amendments.

The only aspects of the EGU definition that EPA is 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 EPA is requesting comment today. The EPA is not reconsidering, and is 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.

The EPA believes 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 or technological differences that warrant use of a different EGU/non-EGU classification methodology for cogeneration units than for other units.

i. 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*, Energy Information Administration, December 1996 at 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:

! the number of [investor owned utilities] has decreased by nearly 8 percent, while the number of non[-]utilities has increased by over 9 percent.

! 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.

! 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.

! 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 1998 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. 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 increasingly irrelevant. These distinctions are increasingly irrelevant in determining whether units are involved in, and should be classified as, producing and selling electricity or whether any units should be classified separately as being owned by monopolies that produce and sell 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. Id. at 3. 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 addition, most 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). In short, future Federal and State actions promoting wholesale or retail competition and deregulation of electricity generation will likely continue the process of removing the distinction between utilities and non-utilities.

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 Energy Information Agency (EIA) is in the process of revising its reporting requirements so that there will no longer be a 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 CBI. Recently, EIA began an effort to reduce, and eventually 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 (explaining that utilities and non-utilities will be subject to the same data protection 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. The EPA believes 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.

ii. Lack of relevant physical or technological differences between cogeneration units and utility electricity generating units

The EPA believes that there are no physical or technological differences between cogeneration units and utility electricity generating units that would prevent cogeneration units classified as EGUs from achieving average NOx reductions similar to those achievable by utility electricity generating units. The EPA also believes that there are 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. 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), post-combustion NOx control technologies, i.e., selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), are available for use on both utility electricity generating units and cogeneration units. The technical support document supports the following conclusions:

- SNCR is a fully commercial technology that uses reagent injected into the furnace above the combustion zone to reduce NOx to elemental nitrogen and water. SNCR 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). SNCR 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).

! SCR is a fully commercial technology that uses both ammonia injected after a unit's combustion and heat transfer zones and catalyst in a reactor to reduce NOx to elemental nitrogen and water. The SCR has been demonstrated on a wide range of boiler types and sizes. Because the NOx reduction takes place in a reactor outside the combustion and heat transfer zones, boiler type has an insignificant impact on the ability to use SCR. The SCR 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. Deactivation or poisoning of SCR catalyst has been alleviated by developing poison-resistant catalysts.

In summary, the same, proven post-combustion NOx control technologies (SNCR and SCR) are applicable to utility electricity generating units and to cogeneration units classified as EGUs.

iii. Conclusion concerning EGU/non-EGU classification methodology for cogeneration units.

For the reasons set forth above in section II.A.2 of today’s preamble, EPA believes 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.[11] 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.

However, in order to provide a transition for units commencing operation before the development of competitive electricity markets or as these markets were emerging, EPA proposes to apply to cogeneration units commencing operation before January 1, 1999 a transitional criterion for EGU/non-

[11] Indeed, it may be appropriate in some future rulemaking to consider all units generating electricity, whether for sale or internal use, as a single category. However, EPA is not proposing to take that further step in today’s rulemaking.

EGU classification. This is the same criterion that was used in the September 24, 1998 NOx SIP Call Rule. Specifically, for cogeneration units commencing operation before January 1, 1999, EPA 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, EPA will generally classify as EGUs all cogeneration units that generate electricity for sale, with the limited exception discussed below in section II.A.3.b of today’s preamble. As also discussed below, this is the same approach that is used for classifying units that are not cogeneration units.

The EPA believes 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 CBI. The EPA does not have, and the petitioner and commenters in the NOx 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 EPA. 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 possible and practical for EPA to apply. For cogeneration units commencing operation on or after January 1, 1999, EPA 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 be treating new data for both utilities and non-utilities as public information, even though EIA will continue to keep historical non-utility data confidential. The EPA, therefore, believes it is practical for EPA or States to obtain electricity sales information for such cogeneration units.

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

i. As noted above, EPA proposes to change the categorization of units used in the NOx 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. The EPA proposes 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 NOx SIP Call. This modification is set forth above in section II.A.2 of today's preamble. Under today's action, for units commencing operation before January 1, 1997, EPA proposes to use the same period (i.e., 1995-1996) to determine the EGU/non-EGU classification of the units as EPA used to calculate the EGU portion of each State's budget under the NOx 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, EPA proposes 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.

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, EPA is 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 EPA 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 NOx 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, EPA believes that it is desirable to have consistent EGU definitions in the NOx 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 NOx 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 (in footnotes 9, 10, 11, and 12 of section II.A.2 of today's preamble), EPA also proposes to use in the NOx SIP Call the same term "potential electrical output capacity," and the same definitions of the terms "electricity for sale under firm contract to the electric grid," "potential electrical output capacity," "nameplate capacity," and "maximum design heat input," adopted in the January 18, 2000 section 126 final rule and used in the EGU definition in the regulations (i.e., part 97) implementing the section 126 program. The basis for these terms and definitions is set forth above in footnotes 9, 10, 11, and 12 of section II.A.2 of today's preamble.

4. 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 State of 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 State of 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 State of 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 NOx 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 NOx 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 NOx 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 not shift any existing cogeneration units from being large EGUs to being large or small non-EGUs.

The EGU/non-EGU classification methodology that EPA proposes 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. The EPA believes 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.

The EPA requests 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, EPA requests 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 EPA believes 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, EPA is concerned about the effect of adopting the one-third potential electrical output capacity/25 MWe sales criteria instead of the proposed methodology. In particular, EPA is concerned that, as discussed above, it lacks the complete, historical information necessary to apply such criteria. Moreover, EPA is concerned that application of such criteria may 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.

The EPA requests 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. The EPA also requests 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, EPA requests that commenters also provide information about each identified unit supporting any claimed EGU, non-EGU, large, or small classifications of the unit.

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 EPA is 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, EPA maintains that this result is reasonable in light of today's changing electricity markets and power industry restructuring.

B. Stationary Reciprocating Internal Combustion Engines (IC Engines)

1. NOx SIP Call

In developing budgets for the NOx SIP Call proposal (62 FR 60318, November 7, 1997), EPA 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 & 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 NOx sources of various sizes and categories at an average cost effectiveness of $1,650/ton; two thirds of the NOx emissions reductions were from only two source categories: non-EGU boilers and IC engines.

In the final NOx SIP Call Rule, EPA 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. The EPA 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, EPA determined, based on the relevant Alternative Control Techniques (ACT) document[12], that post-combustion controls

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[12]Alternative Control Techniques document, “NOx Emissions from Stationary Reciprocating Internal Combustion Engines,” EPA-453/R-93-032, July 1993.

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. March 3, 2000 Court Decision

In the litigation on the NOx 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 EPA did not provide adequate notice and opportunity to comment on the control level assumed for IC engines in its determination of State NOx budgets for the final rule. In Michigan v. EPA, 213 F.3d at 693, the Court agreed and remanded this issue to EPA for further consideration.

The INGAA further contended that the documents that EPA relied on did not support EPA's 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 EPA's definition of "large" IC engine[13]. The Court, however, upheld the Agency's definition of large IC engine, stating that EPA went through

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

an extensive comment period on this issue. Id. at 693-94.

3. Emissions from IC Engines

The large IC engines affected by the NOx SIP Call are primarily used in pipeline transmission service with gas turbines at compressor stations. Uncontrolled NOx emissions from large IC engines are, on average, greater than 3.0 lbs/mmBtu and uncontrolled NOx emissions from gas turbines are about 0.3 lbs/mmBtu. In the NOx SIP Call, EPA 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);[14] and that NOx emissions from large gas turbines (and boilers) can be decreased by highly cost-effective controls to an average region wide emission rate of 0.15-0.17 lbs/mmBtu[15].

In the September 24, 1998 final NOx SIP Call Rule, EPA identified about 300 large IC engines. Subsequently, EPA received information from commenters seeking to make changes to the emissions inventory. The EPA recently made corrections and now includes about 200 large IC engines in

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

[15]NOx SIP Call Rule at 63 FR 57402.

its final NOx SIP Call budget (65 FR 11222). The vast majority of large IC engines included in the budget are natural gas fired.

4. Available Control Technologies for IC Engines

For the NOx SIP Call, EPA 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 EPA’s ACT document for IC engines and application of the following controls: selective non-catalytic reduction (SNCR) for natural gas-fired rich-burn engines and selective catalytic reduction (SCR) for diesel, dual-fuel, and natural gas-fired lean-burn engines. For all large IC engines, except natural gas-fired lean-burn engines (see discussion below), EPA continues to believe that 90 percent control is achievable through SNCR 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)[16] for this proposal. Therefore, EPA proposes to assign a 90 percent emissions decrease on average for large natural gas-fired rich-burn, diesel, and dual fuel IC engines. The

[16]“Stationary Reciprocating Internal Combustion Engines Technical Support Document for NOx SIP Call Proposal,” EPA, OAQPS, September 5, 2000 (IC Engines TSD).

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 NOx controls for IC engines is less than 11 months. Therefore, an implementation deadline of May 31, 2004 is reasonable for the SIP call action which calls for States to adopt and submit rules no later than April 1, 2002.

For natural gas-fired rich-burn IC engines, SNCR 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 NOx emissions.

For diesel and dual fuel engines, SCR provides the greatest NOx reduction of all highly cost-effective technologies considered in the 1993 ACT document and is reported to provide an 80-90 percent reduction in NOx emissions. More recent reports state that NOx emissions can be reduced by greater than 90 percent by SCR. Therefore, EPA estimates NOx reductions for these engines at 90 percent on average. The EPA estimates the population of diesel/dual fuel IC engines are a very small part of the large IC engines population in the NOx SIP Call (less than 3 percent).

5. Natural Gas-fired Lean-burn IC Engines/SCR

Information received by EPA from the natural gas transmission industry after publication of the NOx SIP Call final rule indicate 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, EPA’s 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, EPA now believes there is an insufficient basis to conclude that SCR is an appropriate technology for the large lean-burn engines. Therefore, EPA is 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, EPA believes 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. Natural Gas-fired Lean-burn IC Engines/LEC Technology

Lean-burn engines can reduce NOx 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 NOx formation. The LEC technology involves a large increase in the air/fuel ratio (to ultra-lean conditions) compared to conventional designs.

Emissions of NOx 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 NOx up to 40 percent by air/fuel ratio increases. Further, engines designed to operate at very high air/fuel ratios and with 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. The EPA proposes the following definition, which is similar to the description of LEC technology in the ACT document, and invites 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 NOx 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. The EPA believes application of LEC would achieve NO_x emission levels in the range of 1.5-3.0 g/bhp-hr. This is an 82-91 percent reduction from the average uncontrolled emission levels, on average, reported in the ACT document. The EPA believes that LEC retrofit kits are available for all large lean-burn IC engines. A guaranteed level of 2.0 g/bhp-hr is generally available from engine manufacturers. 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.

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 1.5-3.0 range. That is, while engines that are equipped with LEC technology designed to meet a 1.5-3.0 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 1.5-3.0 g/bhp-hr LEC retrofit level. The EPA requests comment on where and how many large Worthington engines are in the area covered by the NOx SIP Call and what average control level should be expected with application of LEC technology for those engines.

The EPA established statewide NOx 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 NOx. States have the flexibility to adopt the appropriate mix of controls for their State to meet the NOx emissions reduction requirements of the SIP Call. 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, EPA believes 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, EPA does not suggest a technology based standard since an emission rate and continuous emissions monitoring approach can provide more environmental certainty. In this instance, EPA has data identifying the tonnage baseline for each large IC engine, but does not have emission rate (nor heat input) data for each IC engine. Thus, in order to calculate the budget reduction for IC engines, EPA 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, EPA believes that the test data supporting LEC technology may be sufficiently conclusive and that sophisticated emissions monitoring systems, appropriate for emission rate standards or trading programs, may not be needed to assure compliance with IC engine emissions reductions calculated as part of the State budget.

For large natural gas-fired lean-burn IC engines, EPA proposes to assign a percent reduction from within the range of 82-91 percent. Based on additional analysis of available data regarding demonstrated costs, effectiveness, availability, and feasibility of LEC technology, and consideration of comments received in response to the proposal, EPA intends to determine a percent reduction number to use in calculating this portion of the NOx SIP Call budget decrease; the reduction is likely to be from within the 82-91 percent range. The EPA specifically invites comment on the appropriate reduction level that should be used in the final NOx SIP Call budget calculation.

For the control range of 82-91 percent, the average cost effectiveness for large IC engines using LEC technology has recently been estimated to be $520-550/ton.[17] The EPA acknowledges that specific cost-effectiveness values will vary from engine to engine. The key variables in determining average cost effectiveness for LEC technology are the

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

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. The EPA believes the ACT document provides a reasonable approach to calculating cost effectiveness for LEC technology. Further, EPA believes the cost-effectiveness analysis should use updated annualized cost data as described in the IC Engines TSD. For additional information, EPA 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 $510-870/ton (ozone season).

7. Proposed NOx SIP Call Budget Calculations

The EPA proposes 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, EPA proposes to assign a percent reduction from within the range of 82-91 percent. Based on additional analysis of available data regarding demonstrated costs, effectiveness, availability, and feasibility of LEC technology, and consideration of comments received in response to the proposal, EPA intends to determine a percent reduction number to use in calculating this portion of the NOx SIP Call budget decrease; the reduction is likely to be from within the 82-91 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.[18] The Agency invites comment on the control level and associated cost-effectiveness calculations with respect to all IC engine types, and EPA is especially interested in comments regarding the natural gas-fired lean-burn IC engines.

The NOx 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 EPA chooses to use different control levels for rich- and lean-burn IC engines, it would be necessary to estimate the emissions in each category in order to calculate the emissions reductions. The EPA proposes 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.

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

The EPA invites comments on this estimate.

C. Georgia and Missouri

Georgia and Missouri industry petitioners challenged EPA's decision to calculate NOx budgets for these two States based on the entirety of NOx 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 NOx 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 NOx Controls approved by the Policy Group, June 3, 1997 (62 FR 60318, Appendix B, November 7, 1997).

The Court vacated EPA's 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.

[INSERT FIGURE 1]

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.[19] (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.

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

[19] 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.

high 1-hour ozone levels in the downwind ozone problem areas of the fine grid.[20]

Based on OTAG's modeling and recommendations, the technical record for EPA's final NOx SIP Call rulemaking, and emissions data, EPA believes 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, EPA performed State-by-State modeling for Georgia and Missouri as part of the final NOx 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, EPA's 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.

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

Examining the 2007 Base Case[21] NOx emissions for Georgia indicates that the amount of NOx 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 NOx 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.

The EPA sees 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 NOx 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

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

areas compared to the coarse grid part, as described above. The EPA is 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, EPA 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 the EPA findings relating to the SIP call, a State may, of course, assess the in-State impacts of NOx emissions from its coarse grid area, and impose additional NOx reductions, beyond the NOx SIP Call requirements in the fine grid, as necessary to demonstrate attainment of the ozone NAAQS in the State.

The EPA is proposing to revise the NOx 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, EPA believes 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 NOx emissions budgets, EPA believes 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 EPA is including in the calculation of NOx budgets for each of these States are listed in Table 1.

Table 1. Fine Grid Counties in Georgia and Missouri

Georgia			
Baldwin Co	Effingham Co	Jefferson Co	Putnam Co
Banks Co	Elbert Co	Jenkins Co	Rabun Co
Barrow Co	Emanuel Co	Johnson Co	Richmond Co
Bartow Co	Evans Co	Jones Co	Rockdale Co
Bibb Co	Fannin Co	Lamar Co	Schley Co
Bleckley Co	Fayette Co	Laurens Co	Screven Co
Bulloch Co	Floyd Co	Lincoln Co	Spalding Co
Burke Co	Forsyth Co	Lumpkin Co	Stephens Co
Butts Co	Franklin Co	McDuffie Co	Talbot Co
Candler Co	Fulton Co	Macon Co	Taliaferro Co
Carroll Co	Gilmer Co	Madison Co	Taylor Co
Catoosa Co	Glascock Co	Marion Co	Towns Co
Chattahoochee Co	Gordon Co	Meriwether Co	Treutlen Co
Chattooga Co	Greene Co	Monroe Co	Troup Co
Cherokee Co	Gwinnett Co	Morgan Co	Twiggs Co
Clarke Co	Habersham Co	Murray Co	Union Co
Clayton Co	Hall Co	Muscogee Co	Upson Co
Cobb Co	Hancock Co	Newton Co	Walker Co
Columbia Co	Haralson Co	Oconee Co	Walton Co
Coweta Co	Harris Co	Oglethorpe Co	Warren Co
Crawford Co	Hart Co	Paulding Co	Washington Co
Dade Co	Heard Co	Peach Co	White Co

Dawson Co	Henry Co	Pickens Co	Whitfield Co
De Kalb Co	Houston Co	Pike Co	Wilkes Co
Dooly Co	Jackson Co	Polk Co	Wilkinson Co
Douglas Co	Jasper Co	Pulaski Co	
Missouri			
Bollinger Co	Iron Co	Oregon Co	St. Francois Co
Butler Co	Jefferson Co	Pemiscot Co	St. Louis Co
Cape Girardeau Co	Lewis Co	Perry Co	St. Louis City
Carter Co	Lincoln Co	Pike Co	Scott Co
Clark Co	Madison Co	Ralls Co	Shannon Co
Crawford Co	Marion Co	Reynolds Co	Stoddard Co
Dent Co	Mississippi Co	Ripley Co	Warren Co
Dunklin Co	Montgomery Co	St. Charles Co	Washington Co
Franklin Co	New Madrid Co	St. Genevieve Co	Wayne Co
Gasconade Co			

D. Alabama and Michigan

The EPA is 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 NOx SIP Call, the Court’s reasoning regarding Georgia and Missouri applies equally to Alabama and Michigan. Based on the information in the record, EPA is proposing to revise the NOx budgets for Alabama and Michigan to reflect reductions only in the fine grid portions of these States. Again, like Georgia and Missouri, EPA sees 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 NOx 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 NOx emissions per square mile are more than 500 percent greater in the fine grid than in the coarse grid portion of this State. The counties in Alabama and Michigan that EPA is including in the calculation of NOx budgets for each of these States are listed in Table 2.

Table 2. Fine Grid Counties in Alabama and Michigan

Alabama

Autauga Co	Colbert Co	Greene Co	Macon Co	St. Clair Co
Bibb Co	Coosa Co	Hale Co	Madison Co	Shelby Co
Blount Co	Cullman Co	Jackson Co	Marion Co	Sumter Co
Calhoun Co	Dallas Co	Jefferson Co	Marshall Co	Talladega Co
Chambers Co	De Kalb Co	Lamar Co	Morgan Co	Tallapoosa Co
Cherokee Co	Elmore Co	Lauderdale Co	Perry Co	Tuscaloosa Co
Chilton Co	Etowah Co	Lawrence Co	Pickens Co	Walker Co
Clay Co	Fayette Co	Lee Co	Randolph Co	Winston Co
Cleburne Co	Franklin Co	Limestone Co	Russell Co	

Michigan

Allegan Co	Eaton Co	Kalamazoo Co	Monroe Co	St. Clair Co
Barry Co	Genesee Co	Kent Co	Montcalm Co	St. Joseph Co
Bay Co	Gratiot Co	Lapeer Co	Muskegon Co	Sanilac Co
Berrien Co	Hillsdale Co	Lenawee Co	Newaygo Co	Shiawassee Co
Branch Co	Ingham Co	Livingston Co	Oakland Co	Tuscola Co
Calhoun Co	Ionia Co	Macomb Co	Oceana Co	Van Buren Co
Cass Co	Isabella Co	Mecosta Co	Ottawa Co	Washtenaw Co
Clinton Co	Jackson Co	Midland Co	Saginaw Co	Wayne Co

Today, EPA is 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. The EPA believes 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.[22]

E. Modifications to NOx Emissions Budgets

Today, EPA is proposing a small change in the statewide emissions budgets. The EPA is 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, EPA is 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) EPA is 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, EPA is applying the 82-91 percent range to all large IC engines for the purpose of roughly estimating this portion of the proposed budget. Therefore,

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

EPA is 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.

The EPA is 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.

The EPA's proposed budgets are shown in Tables 3 - 6. For States that choose to submit Phase I SIPs, Tables 7 and 8 show the incremental difference between Phase I and Phase II. Several States have already submitted SIPs that meet the entire budget. However, other States may have submitted, or intend to submit at first, only a Phase I SIP. The EPA proposes 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	42,849	3,166	7%
Delaware	23,798	22,861	937	4%
District of Columbia	6,471	6,658	-187	-3%
Illinois	368,870	271,901	96,969	26%
Indiana	340,654	230,381	110,273	32%
Kentucky	237,415	162,519	74,896	32%
Maryland	103,476	81,947	21,529	21%
Massachusetts	87,092	84,922	2,170	2%
New Jersey	105,489	96,876	8,613	8%
New York	255,653	240,322	15,331	6%
North Carolina	224,697	165,306	59,391	26%
Ohio	373,223	249,541	123,682	33%
Pennsylvania	345,201	257,928	87,273	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	210,784	180,521	30,263	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	42,849	3,166	7%
Delaware	23,798	22,861	937	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	237,415	162,242	75,173	32%
Maryland	103,476	81,892	21,584	21%
Massachusetts	87,092	84,838	2,254	3%
New Jersey	105,489	96,876	8,613	8%
New York	255,653	240,285	15,368	6%

North Carolina	224,697	164,987	59,710	27%
Ohio	373,223	249,241	123,982	33%
Pennsylvania	345,201	257,551	87,650	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	210,784	180,154	30,630	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 NOx 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	42,849	42
Delaware	23,522	22,861	661
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 NOx 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	42,849	42
Delaware	23,522	22,861	661
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. Compliance Supplement Pools

As further explained in section II.J.2, 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). The Court of Appeals for the District of Columbia Circuit has recently 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, EPA is extending the time that allowances from the compliance supplement pool can be used from September 30, 2004 to September 30, 2005 to be consistent with the original two year window specified in the SIP Call in which EPA allowed the compliance supplement pool allowances to be used.

The EPA is 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, EPA has 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 NOx SIP Call reflecting full State emissions budgets, EPA proposes to make corresponding decreases to the compliance supplement pools for the portion of the State that is still subject to the SIP Call. The EPA proposes 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 EPA is proposing for the partial-State to the reductions that EPA required in the March 2, 2000 Technical Amendment (65 FR 11222) with one exception. To be consistent with the way the compliance supplement pool was calculated in the other States, EPA is 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 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. 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 NOx SIP Call and Phase III of the Ozone Transport Commission (OTC) NOx 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 NOx SIP Call reduction responsibilities because the budget redistribution did not result in a higher combined overall EGU budget for the three States. The EPA 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). The Agency 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 EPA proposed in response to the three-State MOU.

H. Conformity

The EPA wishes 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 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. Partial-State Trading

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

J. Dates

1. SIP Submittal Due Date for Phase II NOx Budgets

In today's action, EPA is proposing a range of due dates for States to submit SIPs meeting the Phase II NOx budgets and the partial State budgets for Georgia and Missouri. The EPA believes that the appropriate timeframe to consider for SIP submittal is 128 days through 1 year from final promulgation of this rulemaking but no later than April 1, 2002, and is requesting comment on which date within this timeframe is appropriate. The EPA believes that a deadline within the range of 128 days through 1 year from final promulgation of this rulemaking but no later than April 1, 2002 will allow adequate time for States to promulgate rules and for sources affected by a State's Phase II NOx strategy and by Georgia and Missouri's NOx strategy to comply with the regulations by May 31, 2004. Please see section J.2., below, for a discussion of the compliance date.

In the Court's June 22, 2000 order lifting the stay of the SIP submission date for the NOx SIP Call, the Court gave the States 128 days from the date of the order to submit their SIPs. The original submittal deadline was September 30, 1999. On May 25, 1999, the Court stayed that deadline pending further order. At the time of the stay, covered States had 128 days left to submit their SIPs. Therefore, the Court thought it appropriate that the States be given that amount of time to complete their plans for submittal to

EPA. The EPA uses the same rationale for submittal of the Phase II SIP in establishing the beginning of the range of possible due dates. In establishing the end of the range, EPA considered the fact that the original NOx SIP Call Rule allowed 12 months from the date of promulgation for SIPs to be due. The EPA is hopeful that we can finalize this rulemaking in early Spring 2001. The purpose of having an end date to the range, i.e., April 1, 2002, is to ensure that there is a regulatory structure in place to provide the necessary reductions in an expeditious manner to minimize ozone transport.

The EPA believes that a SIP submittal due date within the proposed range would give States adequate time to adopt rules. In addition, sources should be on notice of the regulations States will include in their SIPs sooner than the SIP submittal date itself.

2. Compliance Date

There are two primary issues that need to be considered when determining a reasonable date by which sources 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?

The EPA is proposing a compliance date of May 31, 2004 for sources States elect to cover under a Phase II SIP (Phase II sources) and for all affected sources in Georgia and Missouri, and is taking comment on the feasibility of that date. The EPA maintains that a May 1, 2004 compliance date is feasible for Phase II sources and affected sources in Georgia and Missouri. However, in an effort to remain consistent with the August 30, 2000 District of Columbia Circuit Court of Appeals decision regarding the compliance date for Phase I of the NOx SIP Call, EPA is proposing a compliance date of May 31, 2004.

Given a Phase II and Georgia and Missouri SIP submittal date as late as April 1, 2002, owners and operators of affected units subject to State control requirements would have about 28 months to install the necessary controls. As explained below, EPA maintains that it is technically feasible for all large EGUs that are in the NOx SIP Call region and that are not affected by the section 126 action to meet the emission reduction requirements of Phase II in a 24 month period and that installing controls in that time period will not have an adverse effect on the reliability of the electric power system.[23] The discussion below supports a Phase II SIP submittal date as late as April 1, 2002 for the 19 States and District of Columbia, as well as a April 1, 2002 SIP submittal date for Georgia and Missouri. Of course, submitting the SIP earlier would provide additional time for the installation of controls.

a. Technical Feasibility of May 2004 Compliance Date

As part of the NOx SIP Call, the Agency conducted a detailed examination of the feasibility of installing the NOx controls on large EGUs that EPA assumed in developing the emissions budgets for the affected States. See *Feasibility of Installing NOx Control Technologies By May 2003*, EPA, Office of Atmospheric Programs, September 1998, NOx SIP call rule, A-96-56, V-C-12 ("NOx SIP Call Feasibility Study"). The Agency's findings are summarized in the NOx SIP Call final rule (63 FR at 57447, October 27, 1998).

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[23] Although States may choose to regulate other sources, EPA's analysis is based on the type of EGU's that form the basis for the Phase II budgets since EPA cannot anticipate the sources States may choose to regulate. Moreover, as EPA provided during the SIP Call rulemaking, EPA generally believes that EGUs are the sources that will need the largest compliance time.

For today's proposed action, EPA examined the feasibility of affected units meeting a compliance date of May 31, 2004 to install NOx controls based on a SIP submission date as late as 28 months prior to May 31, 2004. Many sources that States could choose to regulate under the NOx SIP Call are already subject to regulation. Under section 126, EPA 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 NOx SIP Call significantly contribute to nonattainment in one or more of the petitioning States. That rule directly regulates sources within the 13 States and requires compliance by May 1, 2003. 64 FR 28250 (May 25, 1999) and 65 FR 2674 (January 18, 2000). Thus, the affected units in these States or parts of these States are required to meet a May 1, 2003 compliance date under the section 126 action. In addition, as part of the OTC NOx Budget Program, the remaining Northeast States covered in today's action (Connecticut, Massachusetts, New York and Rhode Island) have submitted SIPs for EPA approval to comply by May 1, 2003 with the NOx SIP Call.

The sources covered by State rules already adopted as part of the OTC NOx Budget Program and the sources covered by the section 126 action must comply as required by May 1, 2003. The EPA examined the feasibility of the May 31, 2004 compliance date for the Phase II affected units in the remaining States or parts of States that are not included in either the section 126 action or the OTC NOx Budget Program. These remaining States include: Alabama, Georgia, Illinois, Missouri, South Carolina, and Tennessee and portions of Indiana, Kentucky and Michigan. The EPA 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 NOx control retrofits. In this feasibility analysis, EPA looked at the retrofits EPA projected were needed for affected units in Georgia and Missouri and Phase II units in the remaining States to comply with the NOx SIP Call.

The timeframe for completing installations of post-combustion NOx control devices depends on the type and number of control devices that must be installed on combustion units used to generate electricity. The EPA concluded that the amount of time required to install controls was driven by the plants which were projected to install SCR on the greatest number of units. For affected units in Georgia and Missouri and Phase II units in the remaining NOx SIP Call States, EPA's analysis predicts that a maximum of two SCR retrofits will occur at a single plant, with three plants needing two SCRs and the remaining plants needing one or no SCR retrofits (September 2000 Feasibility Memorandum, docket #A-96-56, item #XII-K-46). Based on the timing assumptions in the NOx SIP Call Feasibility Study, all the predicted retrofits for affected units in Georgia and Missouri and Phase II units in the remaining SIP call States (those plants with two or fewer SCR retrofits) could be completed in about 24 months or less (September 2000 Feasibility memorandum, docket #A-96-56, item #XII-K-46).

The EPA notes that recent experience indicates that NOx control technologies can be installed on a faster timeframe than those assumed in the NOx SIP Call Feasibility Study (which was completed in 1998). Recent OTC experience indicates that a single unit SCR retrofit can be completed in less than 1 year, as opposed to the 21 months assumed in EPA's feasibility analysis. (See Letter to Peter Tsirigotis, EPA, from Charles Carlin, Northeast Utilities Service Company, November 30, 1999; and "Selective Catalytic Reduction Retrofit of a 675 MWe Boiler at AES Somerset," ICAC Forum 2000, March 2000; docket #A-96-56, items #XII-K-15 and #XII-K-18.) These OTC SCR retrofits were designed for 90 percent removal efficiency (as opposed to the 80 percent removal efficiency assumed in EPA's analysis) and included the integration of engineering and construction to complete the retrofit project in a minimum amount of time.

b. 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.

The EPA does not anticipate that the installation of NOx 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’s study concentrated on installation of SCR because that is the control that takes the longest to install. There is general agreement that other controls can be installed within a normally scheduled outage. For instance, in their study, NERC stated “It was assumed that only units requiring the installation of SCR could potentially require extensions to their normal planned maintenance outages. All other applications of the various mitigation technologies were assumed to be performed within the scope of planned outages without extension” (RAS NOx Study, Reliability Impacts of the EPA NOx SIP Call,” docket #A-96-56 at 12).

As discussed further below, EPA and other industry groups examined the reliability of the power supply in the context of a May 2003 compliance date for the entire NOx SIP call region. Based on these studies, EPA concludes that installation of NOx controls for the entire NOx SIP Call region (includes 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, EPA concludes 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.[24]

c. EPA's reliability study

In the NOx SIP Call Feasibility Study, which focused on installing NOx controls by May 1, 2003, EPA examined the effect that the installation of controls would have on reliability. First, EPA examined a scenario where SCR would have to be installed on 72.9 GW worth of capacity (amount of SCR predicted by EPA needed to comply with the NOx SIP Call). Most of the SCR installations EPA has looked at both in the U.S. and abroad have required units to be off-line for less than 5 weeks and, in some cases, less than 1 week (Feasibility Study, Appendix B, Letter from Steag Environmental Engineering and Consulting.)[25] The EPA also examined historical outage times and determined that the

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[24]As explained above, EPA assumes 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, Georgia, Illinois, Missouri, South Carolina, Tennessee and portions of Indiana, Kentucky and Michigan) will have until May 31, 2004 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.

[25]This estimate is further supported by recent experience of sources in New Hampshire, Missouri, and Tennessee. (See Letter to Peter Tsirigotis, EPA, from Charles Carlin, Northeast Utilities Service Company, November 30, 1999; "Design and Initial Startup Results from the New Madrid SCR Retrofit Project," ICAC Forum 2000, March 2000; and "Implementation of SCR System at TVA Paradise Unit 2," ICAC Forum 2000, March 2000; docket #A-96-56, items #XII-K-15, #XII-K-01, and #XII-K-19.

average unit underwent a 5-week maintenance outage (NOx SIP Call Feasibility Study at 12). Therefore, EPA's analysis assumed that all units underwent 5-week maintenance outages and that the SCR could be installed during these maintenance outages. The EPA also assumed that the longest amount of time any plant would need to install SCR would be 34 months. This time period was based on EPA's analysis of the longest amount of time that it would take any plant to install all of the controls projected by EPA (i.e., installing six SCRs at a plant), as explained above. The EPA's analysis concluded that the reliability of the power supply would not be threatened by implementing the NOx SIP Call.

The EPA also performed a sensitivity analysis in which EPA shortened the available time to install controls and lengthened the time that a unit would have to be off-line. The worst case scenario that EPA examined was a situation in which SCR needed to be installed on 63 GW[26] worth of capacity, units needed to be taken off-line for 9 weeks (a 4-week extension of the typical maintenance outage) and there was only 1 year in which to install all of the

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[26] The EPA initially looked at a scenario requiring 63 GW of retrofitted SCR, rather than the 72.9 GW in the final rule (a 14 percent increase). Because of the stringency of the assumptions, the initial analysis still supports the conclusion that reliability will not be impacted under a scenario with 72.9 GW of SCR installed over a 2-year time period.

controls. In this scenario, EPA still found that the power supply would not be threatened and that there was adequate capacity available to supply the needed electricity to thereby avoid brown-outs (Feasibility Study at 13 and 19). Furthermore, as discussed above, many sources in affected States have begun the planning (engineering studies) or installation of SCR retrofits for compliance with the NOx SIP Call and/or the section 126 actions. (See "Recent Experiences in SCR System Design," ICAC Forum 2000, March 2000, docket #A-96-56, item #XII-K-17; ”Design and Initial Startup Results from the New Madrid SCR Retrofit Project," ICAC Forum 2000, March 2000, docket #A-96-56, item #XII-K-01; "Implementation of SCR System at TVA Paradise Unit 2," ICAC Forum 2000, March 2000, docket #A-96-56, item #XII-K-19; "Implementation of SCR at Southern Company", 2000 Conference on Selective Catalytic Reduction for NOx Control, May 2000, docket #A-96-56, item #XII-K-12, List of United States SCR Installations, Clyde Bergeman, February 2000, docket #A-96-56, item #XII-K-13). Some of these SCR retrofit projects are being planned for start-up in 2000 and 2001 to take advantage of early reduction credits. This early installation will also reduce system reliability concerns since less SCR will have to be installed in 2002 and the first half of 2003.

d. Other reliability studies

Since EPA finalized the NOx SIP Call, the North American Electric Reliability Council (NERC), the Eastern Central Area Reliability Council (ECAR), and the Ozone Attainment Coalition (OAC) have also done studies on the effects that the NOx SIP Call could have on reliability. ("RAS NOx Study, Reliability Impacts of the EPA NOx SIP Call," docket #A-96-56, item #XII-K-06, and "ECAR Reliability Analysis of the EPA NOx SIP Call," docket #A-96-56, item #XII-K-07.)

The OAC developed two reports that assessed the feasibility of NOx SIP Call compliance by affected sources in the context of electric system reliability. See "Electric System Reliability - A Red Herring to Delay Clean Air Progress," Ozone Attainment Coalition, September 1998, docket #A-96-56, item #XII-K-45 and "NOx SIP Call Compliance and Electric System Reliability: Compatible Goals for Achieving Needed Air Quality Benefits," Ozone Attainment Coalition, May 1999, docket #A-96-56, item #XII-K-11. The September 1998 report concluded that, even with conservative assumptions about outage periods for the installation of SCR controls, compliance with the NOx SIP Call can be achieved in aggregate by the affected sources. Additional OAC analysis, conducted in May 1999, examined a low growth and high growth case with SCR installations on 222 to 258 electric utility units (83.3 GW to 97.8 GW of capacity), as compared to EPA's estimate of 142 units (72.9 GW of capacity). The analysis also assumed a 6-week outage period for SCR hook-up, as compared to EPA's assumption of 5 weeks, and assumes that SCR hook-ups will occur outside of the ozone season. The OAC analysis predicts that the NOx SIP Call will result in approximately 1 percent additional capacity under the high growth case having to be off-line in each of the affected NERC control regions. The analysis concludes that the impacts under either case are small enough to be well within the variability of the forced (e.g., unplanned or non-routine) outage rates.

to which reliability planners routinely respond.

The NERC did a study on the entire NOx SIP Call region. As the report explains, “The scenarios discussed in this report were chosen after a screening study was performed to identify candidate scenarios that were likely to result in any significant adverse impact on reliability....As such, some scenarios may not be representative of conditions that are most likely to occur.” One of the scenarios that NERC examined assumed that 72.9 GW worth of SCR would have to be installed, that there would be 18 months available to install the SCR, and that it would require an outage of 9 weeks. The amount of time to install the controls is shorter than that being proposed here and the outage time required to install controls is longer than has been needed in actual retrofits. Even under this conservative scenario, NERC determined that installation of controls would not adversely affect the reliability of the electric system.

The NERC did predict that there could be reliability problems in a scenario where there would be only 18 months to install NOx controls, 151.0 GW of SCR would have to be installed and average outages of 9 weeks would be required. The EPA believes that this combination of circumstances is very unrealistic. Based on EPA’s compliance deadline, sources will have more than 2 years to install controls. With regard to the assumption of 151.0 GW of SCR, this is more than twice as much SCR as EPA has predicted. This assumption is based in part on the belief that SNCR cannot be installed on units that are larger than 350 MWe. In fact, SNCR has been installed on a number of units that are larger than 350 MWe (See "Cardinal Unit 1 Large Scale Selective Non-Catalytic Reduction Demonstration Project," ICAC Forum 2000, March 2000; and "Start-Up Results and Next Steps for the Commercial NOxOUT System at a 600 MWe Coal Fired Electric Utility Unit," 2000 NETL Conference on Selective Catalytic & Non-Catalytic Reduction for NOx Control, May 2000, docket A-96-56#, items #XII-K-16 and #XII-K-14). Further, as explained above, EPA believes that

5 weeks or less is a much more realistic estimate for the amount of time a unit needs to be shut down in order to install SCR.

The ECAR's study concludes that there would be a significant impact on reliability in all scenarios that ECAR considered. The ECAR includes the States of Indiana, Kentucky, Michigan, Ohio, and West Virginia, as well as parts of Maryland, Pennsylvania and Virginia. The ECAR includes about 100 GW out of the 250 GW of generation in the SIP Call Region. As explained below, EPA disagrees with a number of the assumptions in ECAR's study and therefore disagrees with the conclusion that there will be a significant impact in reliability under all scenarios. A key factor in ECAR's analysis is that, as part of the base case assumptions, each unit would be available 80.3 percent of the time. As the report explains, this is the lowest average availability that the system could have without having reliability problems. Since this assumption is part of the base case, any additional time that units are assumed to be off-line to install controls further reduces the average availability, leading to the conclusion that any installation of controls would lead to a significant impact on reliability. However, the report fails to explain why 80.3 percent is an appropriate availability to assume for the base case. The ECAR has had an average availability over the last 5 years of 82.3 percent and the average over the last 10 years is 81.6 percent (ECAR’s “Assessment of ECAR-Wide Capacity Margins 1999-2008," docket #A-96-56, item #XII-K-10). The ECAR’s reliability report also shows that if an average availability of 81.6 percent (ECAR average availability over the last 10 years) is assumed, all of the SCR that it assumes is needed could be installed in an 18-month period, with a 4-week outage extension (total outage of 9 weeks) to install SCR, and without significantly impacting reliability.

Similar to NERC, ECAR also assumes that much more SCR will be needed than EPA does. The ECAR assumes that SCR will need to be installed on 55.6 GW of capacity in the ECAR region. The EPA projects that SCR will need to be installed on 36.3 GW worth of capacity in the ECAR region. The ECAR study also makes overly conservative assumptions about the amount of generation that may come on line over the next several years. The ECAR assumes that approximately 9,900 MWe of generation will come on line by 2008 (ECAR’s “Assessment of ECAR-Wide Capacity Margins 1999-2008," docket #A-96-56, item #XII-K-10). This equates to a little more than 1,200 MWe a year. The Electric Power Supply Association reports that over 10,000 MWe of capacity have been announced to come on line before 2003 in the ECAR region. (docket #A-96-56, item #XII-K-08). This equates to over 3,000 MWe a year. Cambridge Energy Research Associates reports that over 3,000 MWe worth of capacity are currently under construction in the ECAR region and scheduled to come on line in the year 2000. In the year 2001, another 3,000 MWe worth of capacity are proposed by electricity suppliers to come on line and over 1,000 MWe of this capacity is already under construction. In the year 2002, over another 5,000 MWe worth of capacity are proposed by electricity suppliers to come on line. (Docket #A-96-56, item #XII-K-09). Any additional capacity beyond that assumed by ECAR would reduce the potential impact of the installation of controls on reliability as projected by ECAR's analysis. In fact, the ECAR study explains that under all scenarios considered, the impact on reliability would be negated if an additional 2,460 MWe worth of capacity were built in time for the 2002 ozone season. As noted, well over that amount of capacity is already under construction or is proposed to be built by the 2002 ozone season.

Furthermore, because of ECAR's capacity margin assumptions, the ECAR study also shows that most of its projected reliability problems will occur in the summer when units are not projected to shut down for the installation of controls. In its base case, ECAR predicts monthly capacity margins (a measure used to determine system reliability) of less than 9.0 percent in July of 2001, 2002 and 2003. The lowest capacity margin it predicts during the summer months is 7.4 percent in July of 2002. Since ECAR does not anticipate companies installing controls in the summer (June, July and August), ECAR predicts these same summer time capacity margins in all of the scenarios that ECAR studied. Lower capacity margins lead to greater potential reliability problems. Consequently, the reliability problems projected to occur would occur with or without the installation of controls. In the worst case scenario, all controls were installed in an 18-month window and the lowest capacity margin predicted in a month where controls were actually being installed was 9.5 percent in September of 2002. Based on these assumptions, this clearly shows that, under the ECAR study, the likelihood of reliability problems is in the summer months during which no installation of emission controls are expected to occur. Thus, the projected reliability problems are largely independent of the NOx SIP Call.

K. Wisconsin

In the NOx 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 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 NOx 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.

The EPA’s “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 modeled by EPA, 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 NOx SIP Call rulemaking, EPA 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 EPA 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.

The EPA agrees 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 NOx SIP Call at this time. Since EPA does not currently have the modeling necessary to make such a proposal, EPA intends to exclude the entire State of Wisconsin from the requirements of the 1-hour basis of the NOx SIP Call to conform to the Court's decision.

The EPA is not, however, proposing to determine that Wisconsin's emissions do not contribute significantly to nonattainment downwind. The EPA has not completed the additional modeling analysis for the States that are part of the OTAG region but were not included in the final NOx SIP Call. In the final NOx SIP Call, EPA took no action on whether emissions from sources in 15 States[27] 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. The EPA will continue to review available information on the downwind impacts of these States. The EPA plans to look at the impacts of Wisconsin in conjunction with any further

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

analysis on the remaining 15 States. To date, the Court has stayed consideration of the 8-hour basis of the SIP Call rule and thus did not consider the 8-hour basis for the Rule in its opinion. The EPA has stayed the 8-hour basis of the SIP Call Rule (65 FR 56245, September 18, 2000). 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. The EPA will address that issue at the time it lifts the stay as it applies to Wisconsin.

L. Stay of the 8-hour NAAQS Rules

As noted above, the revisions to the NOx 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, EPA has 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, EPA will determine whether to proceed with the 8-hour requirements under the SIP Call. The EPA intends at that time to conduct additional rulemaking that will address SIP submission dates, budget issues (including, for example, revisions as may be necessary to account for the appropriate definition of EGU and the appropriate control level for IC engines), and other aspects of the SIP Call requirements under the 8-hour NAAQS, as may be necessary in light of the Court's analysis for the 1-hour NAAQS.

III. 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 Michigan v. EPA, 213 F.3d 663 (D.C. Cir. 2000), 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,” EPA is preparing a Regulatory Impact Analysis (RIA) which will include cost and benefits analyses and an economic impact analysis. A cost analysis entitled, “NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in the NOx SIP Call States” (June 7, 2000), was 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 NOx SIP Call [“Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions” (Docket A-96-56)]. This document is available for public inspection in Docket A-96-56 which is listed in the ADDRESSES section of this preamble.

B. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 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 NOx SIP Call that would be required by UMRA if its statutory provisions applied and has consulted with governmental entities as would be required by UMRA. Because today's action does not create any additional mandates above those of the NOx SIP Call, no further UMRA analysis is needed.

C. 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 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 this SIP Call, EPA is acting under section 110(k)(5), which requires the Agency to require a State to correct a deficiency that EPA has found in the State implementation plan (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 or vacated and remanded to the Agency for further consideration the issues on which EPA is proposing action today. Michigan v. EPA, 213 F.3d 663 (D.C. Cir. 2000).

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 Alabama and Michigan to be based on partial States; and the SIP submission and source compliance dates, EPA's proposal does not impose any additional burdens beyond those imposed by the final NOx 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.

This action will not impose substantial direct compliance costs. While the State 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.

Notwithstanding that this rule does not have federalism implications, EPA notes that EPA has consulted extensively with the States. The EPA consulted extensively with the affected States during the OTAG process that lead to the initial notice of proposed rulemaking for the SIP Call and conducted substantial outreach efforts to the States and others in the course of developing the SIP Call Rule.

D. Executive Order 13084: Consultation and Coordination with Indian Tribal Governments

On November 6, 2000, the President issued Executive Order 13175 (65 FR 67249) entitled, “Consultation and Coordination with Indian Tribal Governments.” Executive Order 13175 takes effect on January 6, 2001, and revokes Executive Order 13084 (Tribal Consultation) as of that date. However, EPA developed this proposed rule during the period when Executive Order 13084 was in effect; thus, EPA addressed tribal considerations under Executive Order 13084. The EPA will analyze and fully comply with the requirements of Executive Order 13175 before promulgating the final rule.

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

Today's action does not significantly or uniquely affect the communities of Indian tribal governments. This proposed action is in response to the Michigan v. EPA, 213 F.3d 663 (D.C. Cir. 2000) (decision on the NOx SIP Call). The EPA stated in the final NOx SIP Call that Executive Order 13084 did not apply because the final rule does not significantly or uniquely affect the communities of Indian tribal governments or call on States to regulate NOx sources located on tribal lands. The same is true of today’s action. Accordingly, the requirements of section 3(b) of Executive Order 13084 do not apply to this rule.

E. Executive Order 12898: Environmental Justice

In addition, 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 NOx SIP Call, the Agency conducted a general analysis of the potential changes in ozone and particulate matter levels that may be experienced by minority and low-income populations as a result of the requirements of the rule. These findings were presented in the RIA. Today’s action does not affect that analysis.

F. Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 USC 601 et. seq.

The RFA generally requires an agency to prepare a regulatory flexibility analysis of 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 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 Michigan v. EPA, 213 F.3d 663 (decision on the NOx SIP Call) and does not itself establish requirements applicable to small entities.

G. 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 EPA has reason to believe may have a disproportionate effect on children and is not economically significant under Executive Order 12866.

H. 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. The EPA's compliance with these statutes and Executive Orders for the underlying rule, the final NOx SIP Call, is discussed in more detail in 63 FR 57477-81 (October 27, 1998).

I. Paperwork Reduction Act

The EPA stated in the final NOx SIP Call that an information collection request was pending. Today's action imposes no additional burdens beyond those imposed by the final NOx SIP Call. Any issues relevant to satisfaction of the requirements of the Paperwork Reduction Act will be resolved during review and approval of the pending information collection request for the NOx SIP Call.

List of Subjects

40 CFR Part 51

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

40 CFR Part 96

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

Dated:

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Carol M. Browner,
Administrator